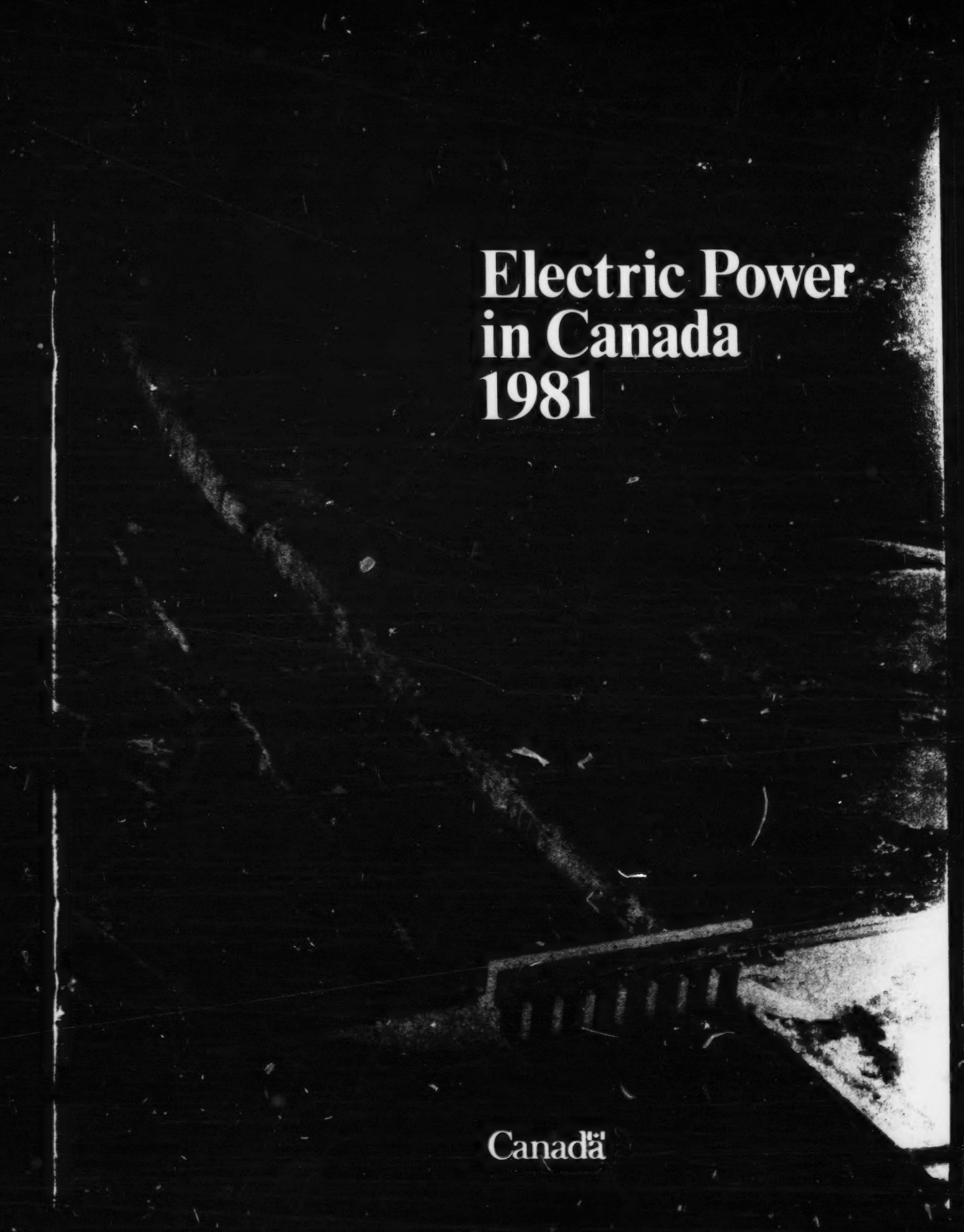

Electric Power in Canada 1981

Canada

Cover: Spillway at Hydro-Québec's LG-2 generating station. The 5328 MW hydro plant, the largest in Canada, was completed in 1981.

Photographs provided through the courtesy of:
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Electric Power in Canada 1981

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DEFINITIONS AND ABBREVIATIONS

Capacity:	The rated ability of facilities to produce or deliver power at a given point in time; for example, installed generating capacity means the maximum amount of power that can be generated at a given point in time.
Power:	The time rate at which electrical energy is made available, typically measured in kilowatts.
Production:	Generation of electrical energy, typically measured in kilowatt-hours.
Consumption:	Use of electrical energy, typically measured in kilowatt-hours.
Power:	kW – kilowatts MW – megawatts = 1 000 kW GW – gigawatts = 1 000 000 kW TW – terawatts = 1 000 000 000 kW
Energy:	kWh – kilowatt-hours MWh – megawatt-hours = 1 000 kWh GWh – gigawatt-hours = 1 000 000 kWh TWh – terawatt-hours = 1 000 000 000 kWh
Voltage:	kV – kilovolt

CONSUMPTION, PRODUCTION and CAPACITY

Consumption

It can be seen in Table 1 that Canadian electricity demand increased by 1.1% during 1981 to an estimated 343 700 GWh. This low rate of growth contrasts with an estimated 3% increase in real Gross National Product (GNP) with which electricity demand has historically had a high degree of correlation. One factor accounting for the low growth in electricity demand was unusually mild weather conditions in a number of regions during the heating season, both at the beginning and end of 1981. In addition, reduced industrial activity in the second half of the year, particularly in the Maritime provinces, also affected growth. However, electricity demand was considerably stronger than that for oil and gas which declined an estimated 7% and 3% respectively.

Table 2, which illustrates electricity demand for each province, shows that Alberta experienced the strongest growth in demand during 1981. Manitoba showed the largest reduction, while in the other provinces electricity demand changed only marginally from 1980 levels.

In the ten-year period since 1970, consumption patterns by sector have changed to some extent, although the general pattern remains the same. The industrial sector consumes the greatest share of the electrical demand, followed by the residential and commercial sectors. However, the amount of the respective shares has changed. Figure 1 illustrates that the residential share of demand has increased substantially while the industrial share has dropped. The commercial sector has also increased to a small extent.

Table 1. Statistical Summary: Totals for Canada 1980-1981

	1981	1980	Percentage Change	Table Reference*
Total Demand for Electricity (GWh)	343 748	340 069	1.08	2
Total Generation (GWh)	377 622	367 306	2.81	2
by: hydro	262 253	251 217	4.39	6
nuclear	37 799	35 863	5.40	A4
conventional thermal	77 570	80 226	–3.31	
Total Net Exports (GWh)	33 875	27 237	24.37	2
total imports	1 497	2 939	–49.06	7
total exports	35 372	30 176	17.22	A5
Total Capacity at December 31, 1981 (MW)	83 308	81 052	2.78	A2
hydro	49 215	47 536	3.53	A3
nuclear	5 600	5 600	–	
conventional thermal	28 493	27 916	2.07	
Total Net Additions to Capacity During 1981 (MW)	2 256	4 742	–52.43	3
hydro	1 679	3 915	–57.11	A6
nuclear	–	–		
conventional thermal	577	827	–30.23	A7

**The tables indicated provide data on a provincial basis*

Foreground: construction of the Bruce B Station. Background: Bruce B Heavy Water Plant in service since 1981. Sister plant, Bruce A (not shown), provided the largest share of electricity in Ontario for the first time ever in 1981. Excess steam from these plants is to be used by industries adjacent to the plant.

Production

Total electricity production increased 2.8% from 1980, to an estimated 377 622 GWh in 1981. Hydro generation accounted for 70%, nuclear 10%, and the remaining 20% was from conventional thermal sources. This increase is related to an increase of 1.1% to meet domestic consumption and a 24.4% increase in net exports to the United States.

A significant occurrence during 1981 was the fact that, for the first time, nuclear generation was the largest contributor to a province's electrical supply. In Ontario, nuclear generation represented 34% of the province's total generation while representing only 22% of total installed capacity. This corresponds to an annual capacity factor of 77%. Eight of Ontario's CANDU units placed in the top fifteen positions in a reliability rating of the world's largest nuclear reactors, including the first six positions in the rankings. This outstanding performance attests to the very effective operating performance of the CANDU reactors.

Capacity

Preliminary figures for additions to generating capacity during 1981 total 2 256 MW. This raises total installed capacity to 83 308 MW, an increase of 2.8% from 1980. Hydro capacity additions totalled 1679 MW, 74% of the total, and conventional thermal additions were 26%. There were no additions to nuclear capacity in 1981. These additions are shown in Table 3.

A major event during 1981 was the completion of the last five 333 MW units of Hydro-Québec's La Grande Site 2 (LG-2) project. The first of the generating stations of the James Bay hydro projects, it was completed ahead of schedule and within its budget, which is a significant

Table 2. Provincial Electricity Supply and Demand

Province	Year	Generation	Net Exports	Total Provincial Demand	1980-81 Demand Growth	1976-81 Compound Annual Growth	1971-81 Compound Annual Growth
			(GWh)			(%)	
Newfoundland	1981	44 665	36 039	8 626	0.95	3.82	6.10
	1980	46 374	37 829	8 545			
Prince Edward Island	1981	31	–484	514	–0.96	2.96	6.51
	1980	127	–392	519			
Nova Scotia	1981	6 569	–192	6 761	–0.78	2.22	5.07
	1980	6 868	54	6 814			
New Brunswick	1981	8 936	147	8 789	–0.54	2.82	6.65
	1980	9 323	486	8 837			
Québec	1981	102 905	–17 584	120 489	1.89	5.12	5.47
	1980	97 917	–20 336	118 253			
Ontario	1981	110 039	3 322	106 717	0.19	2.11	3.88
	1980	110 284	3 774	106 510			
Manitoba	1981	18 431	4 929	13 502	–3.06	2.20	3.93
	1980	19 468	5 540	13 928			
Saskatchewan	1981	9 674	–222	9 896	0.69	5.71	5.70
	1980	9 204	–624	9 828			
Alberta	1981	24 497	92	24 405	5.32	8.49	8.35
	1980	23 451	279	23 172			
British Columbia	1981	51 005	7 827	43 175	0.90	3.22	4.05
	1980	43 416	628	42 788			
Yukon	1981	392	–	392	2.89	1.27	5.12
	1980	381	–	381			
Northwest Territories	1981	480	–	480	–2.83	1.48	4.88
	1980	494	–	494			
CANADA	1981	377 622	33 875	343 748	1.08	3.83	4.91
	1980	367 306	27 237	340 069			

achievement. LG-2 is now the largest single generating station in Canada at 5328 MW, followed by the 5225 MW plant at Churchill Falls. Two other plants (LG-3 and LG-4) totalling 5941 MW, are planned in Phase I of the La Grande complex, which will be completed by 1985.

Details of capacity by energy source and by region are given in Figure 2, while Figure 3 indicates the type of installed capacity and electricity production by principal energy source for each province and Territory. Figure 4 shows the historical installed capacity mix.

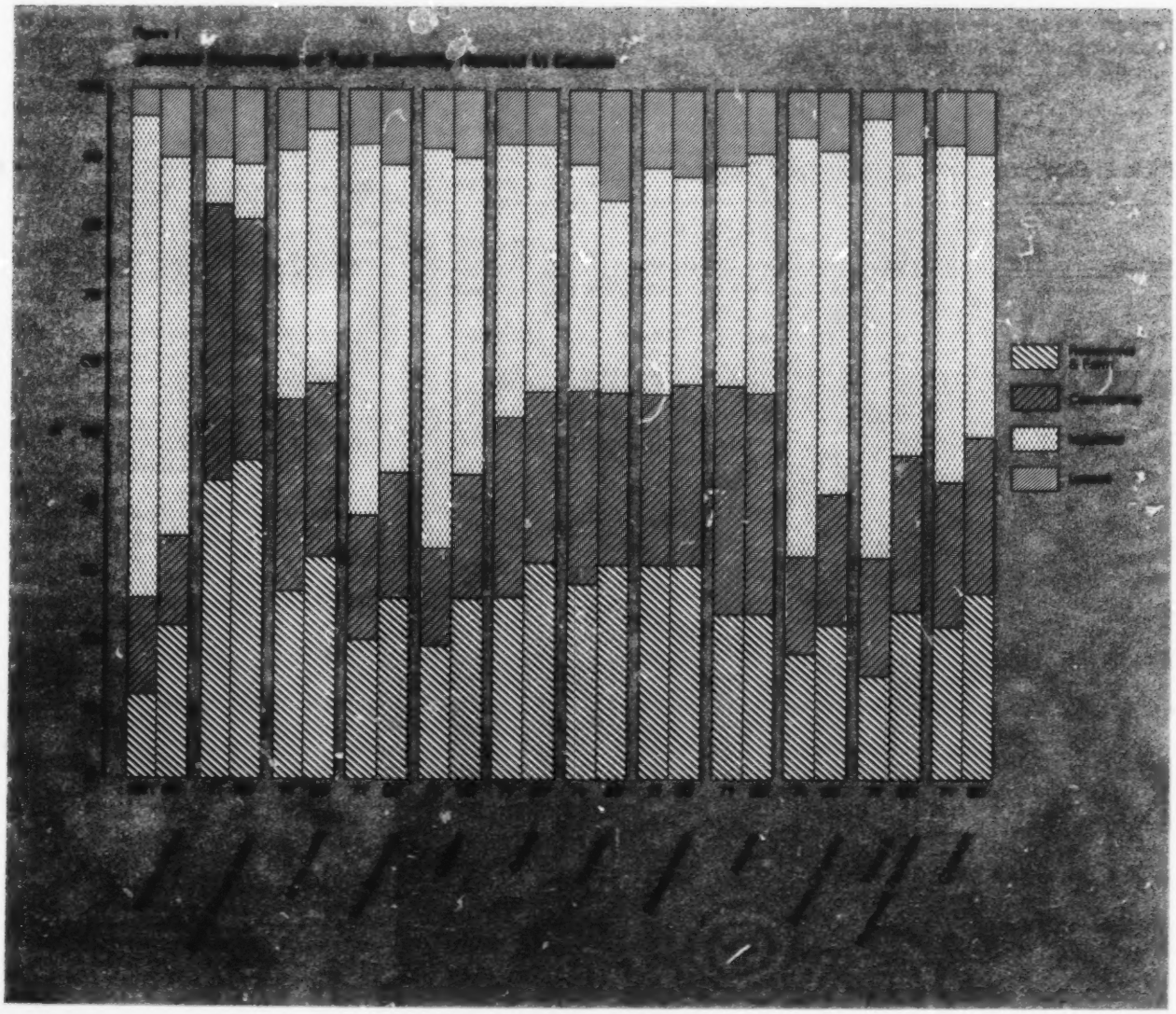


Table 3. Changes in Installed Capacity During 1981

Province	Project Name	Plant Type	Number of Units	Capacity
				(MW)
Additions				
Québec	Beauharnois	hydro	1	46.75
	Bryson	hydro	1	25.00
	La Grande – 2	hydro	5	1 665.00
	Various locations	internal combustion	37	10.54
Ontario	Thunder Bay	steam (coal)	1	149.00
	Pickering B	gas turbine	6	42.00
Alberta	Battle River	steam (coal) (Alberta Power Limited)	1	375.00
TOTAL ADDITIONS				2 313.29
Removed from Service				
Quebec	Beauharnois	hydro	1	37.30
	Bryson	hydro	1	20.00
TOTAL REMOVED				57.30
TOTAL NET ADDITIONS				2 255.99

* *Provincially owned utilities except where indicated.*

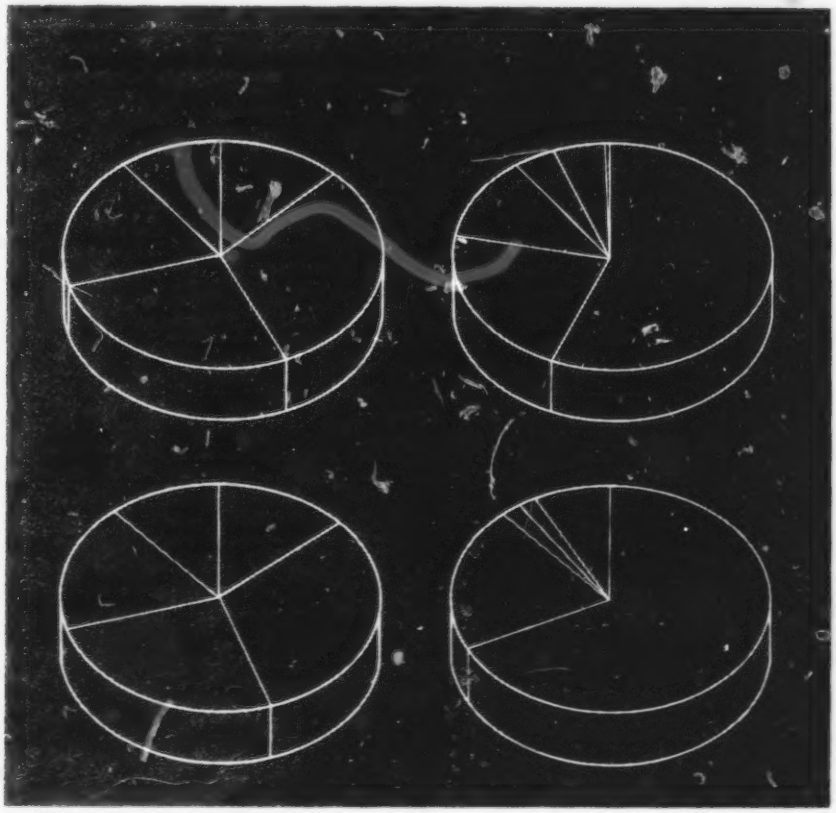
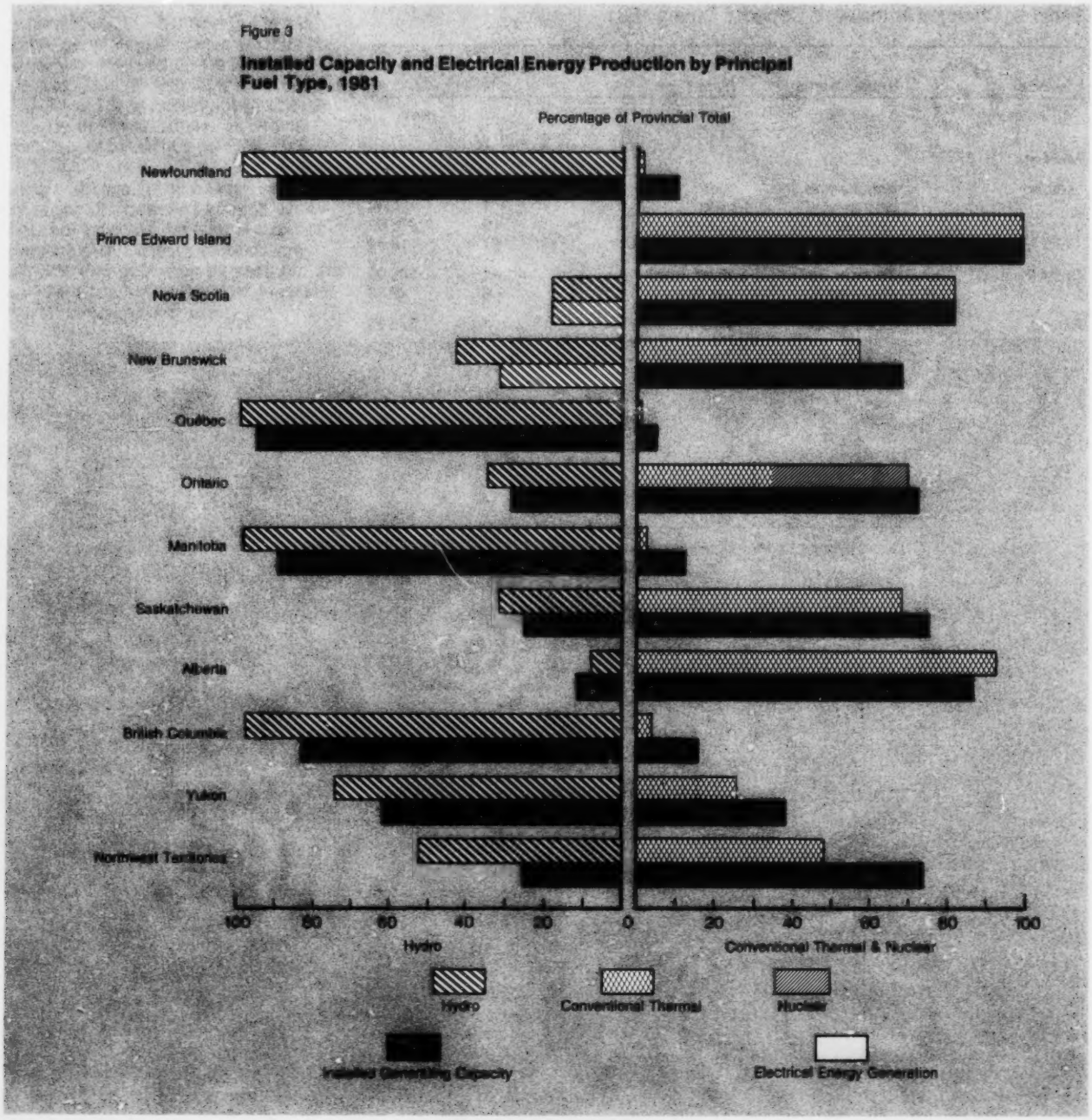
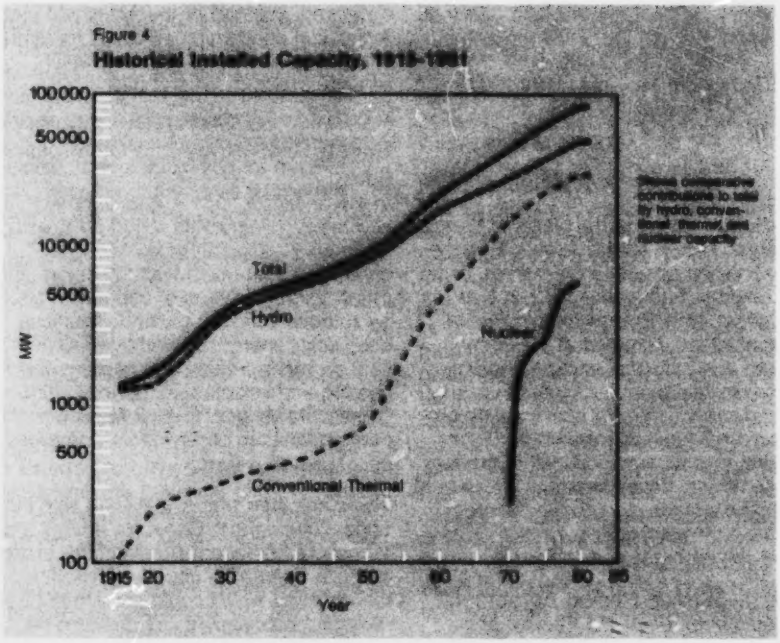
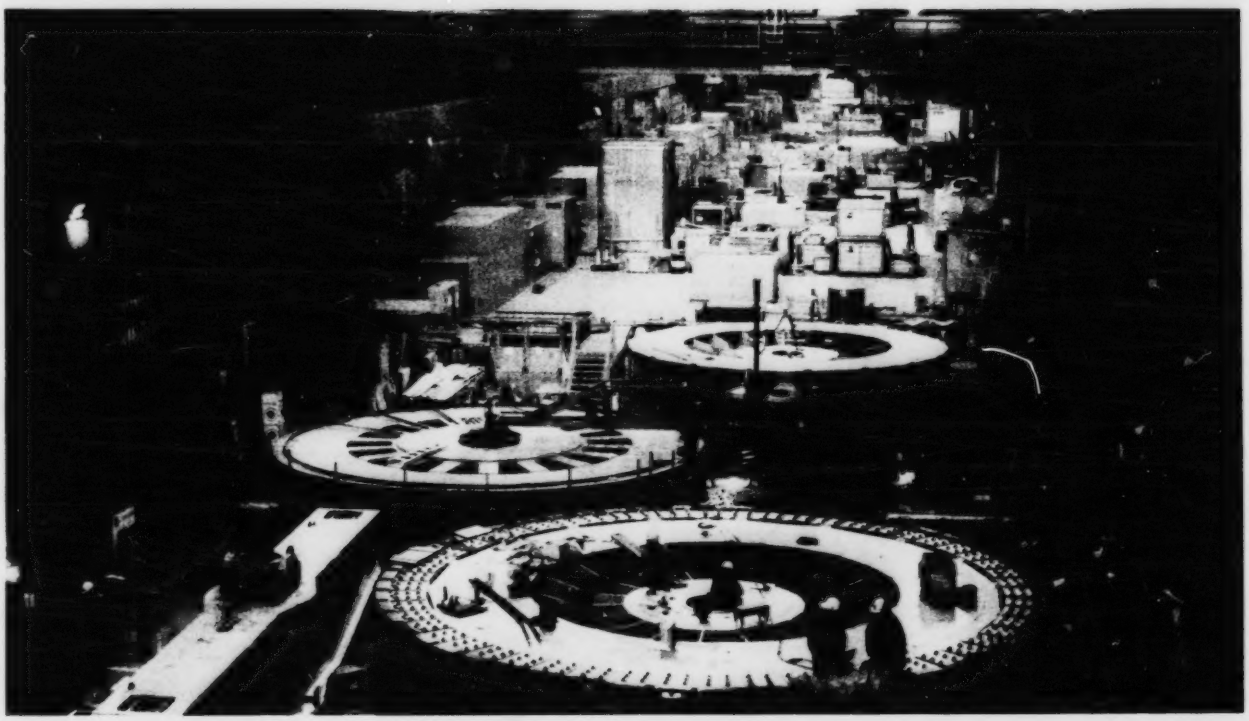


Figure 3

Installed Capacity and Electrical Energy Production by Principal Fuel Type, 1981







View of machine room during construction phase of Hydro-Québec's LG–2 power house, shows work in progress for installation of turbine generators, completed in 1981.

DEVELOPMENTS IN 1981

The following sections provide an overview of some of the more significant events relevant to electricity supply and demand in Canada during 1981.

Federal Policy Developments

Federal energy policy in 1981 focused on the implementation of the National Energy Program, announced in October 1980. A major thrust of this policy is to reduce Canada's dependence on oil by 1990 to 10% of energy used in the industrial, commercial and residential sectors. One of the results will be that electricity will play a greater role in the supply of primary energy. It is anticipated that by 1990, 44% of primary energy will be supplied in the form of electricity, compared to 38% in 1981, and 37% in 1980.

The Role of Electricity in the Canada Oil Substitution Program (COSP)

The Canada Oil Substitution Program was launched in May 1981. It provides taxable grants for up to 50% of the cost of converting from oil to gas, electricity, or renewable energies for space and water heating, to an $800 maximum.

The program is administered by the gas and electric utilities for gas and electric conversions, and by Energy, Mines and Resources Canada offices in each province for renewables. Conversions to electricity are acceptable without any restrictions in Manitoba, Ontario and New Brunswick. Some restraints on conversions to electricity, imposed by EMR and the Provinces, are outlined below. Electric conversions are not eligible for the grant in mainland B.C. where natural gas is available, and not at all on Vancouver Island. No electric conversions are accepted in Saskatchewan. Heat pumps only are accepted in Alberta. Electric conversions are eligible in Québec only if houses are weatherized to meet provincial standards and the central-heating distribution systems continue to be used. No electric conversions are eligible in Nova Scotia at this time. Electric conversions are eligible in only four communities in Labrador and not at all in Newfoundland. Restrictions on conversions to electricity in Atlantic Canada are due to the reliance on oil-fired generation.

It is estimated that over the ten-year period of the program there will be over one million conversions to electricity. This represents 35% of the available stock of oil heated houses today. By the end of 1981, some 27 994 conversions to electricity were assisted by the Federal grant, for a total dollar value of $21,276,000.00.

Atlantic Energy Conservation Investment Program

A further measure of the National Energy Program, known as the Atlantic Energy Conservation Investment Program, came into effect in September 1981 in Newfoundland, New Brunswick and Prince Edward Island. Directed at the commercial and industrial sectors, the program provides taxable grants of up to 50% of capital costs of conservation projects, to a $4 million maximum. Eligible projects include modifications to facilities or operations, development of waste heat recovery systems and cogeneration of electricity. Nova Scotia may be included under the program at a later date.

Alberta-Canada Pricing Agreement

In September 1981, the Federal and Alberta Governments reached an agreement concerning the pricing and taxation of crude oil, natural gas, synthetic crude oil and natural gas liquids produced in Alberta. The bulk of the agreement extends from September 1, 1981 to December 31, 1986, and it is expected to have some impact on the supply and demand for electricity. Under the agreement, prices for home heating oil and natural gas are expected to double by 1986. The price of natural gas is likely to rise more rapidly than electricity prices in most provinces. The share of primary electricity, that is, electricity generated from hydro and uranium, in total energy supply is now estimated at 34% by 1990[1], as compared to a 31% share by 1990[1] in pre-agreement forecasts.

The Energy Security Act

Draft legislation for a new Energy Security Act was introduced into Parliament in June 1981. Of particular interest to the electrical sector is the provision that the National Energy Board would be given authority to expropriate rights-of-way for designated interprovincial transmission lines and all new international lines. If passed, this part of the Act would place legislation concerning electrical transmission corridors on par with that which already exists for oil and gas.

Parliamentary Committee Report on Energy Alternatives and Oil Substitution

In the spring of 1981 a Parliamentary committee released its report on Energy Alternatives and Oil Substitution. The committee's mandate was to explore and report upon utilization of alternative energy sources such as: gasohol, liquified coal, solar energy, methanol, wind and tidal power, biomass, and propane for heating and vehicle use. Special attention was to be paid to their feasibility, impact on balance of payments and overall economic desirability.

The committee was established with the understanding that Canada's energy system should be directed away from hydrocarbons in order to counter environmental problems which could arise in the next century, particularly if coal becomes a principal source of energy supply; and to preserve crude oil, natural gas and coal for such non-energy uses as the production of petrochemicals. A number of their recommendations are relevant to the electrical industry.

The committee recommended the adoption, by the federal government, of an energy system based on hydrogen and electricity as the principal energy currencies. It suggested that utilities should be encouraged to utilize cogeneration technology, and recommended greater Canadian involvement in electric vehicle research, development and demonstration.

In isolated communities, financial assistance was recommended to encourage the installation of small hydro units and appropriate technical assistance was suggested for areas where wind-diesel hybrid systems might be installed.

A further economic feasibility study was suggested to review the conclusions of the 1977 Tidal Power Review Board, regarding tidal power development in the Bay of Fundy. If favorable results are obtained, a definitive 3-year pre-investment study examining design, engineering, socio-economic, and environmental factors would precede tidal power development.

[1] Based on EMR's Interfuel Substitution Demand Model

The committee further recommended acceleration of existing plans for photovoltaics RD&D, and of coal-oil mixture technology RD&D where feasible. Analyses on the federal level of opportunities, benefits and funding requirements of fluidized bed combustion for thermal electricity generation was suggested. Finally, the adoption of the expenditure program for fusion–related research, proposed by the National Research Council, was recommended.

Provincial Policy Developments and Issues

Alberta Electrical Energy Marketing Agency

In an effort to reduce rate differentials throughout the province, and to optimize production of electricity, the Alberta Government passed legislation in November 1981 to create a provincial marketing agency for electricity. Scheduled to be in operation by September of 1982, the agency will purchase power from the utilities, set a province-wide wholesale rate, and resell it to the utilities for distribution. It is estimated that existing rate differentials will be reduced by 80%, the remaining 20% representing distribution costs which are not affected by the agency. The system will be phased-in over a five year period, initially with a subsidy scheme for major cities, which will be reduced over the five years. The agency will buy power from the lowest bidder and will also be able to make purchases from outside the province.

Board of Industrial Leadership and Development (BILD)

To encourage an increasing role for electricity in the Ontario economy, the provincial government outlined a number of electricity-orientated initiative schemes in January 1981. Intended to be part of the BILD program, these schemes included: a 20-year accelerated generation expansion program, including early completion of the Darlington nuclear facilities and upgrading of transmission networks; increased electrification in the transportation sector; increased industrial and commercial use of steam from nuclear facilities; and the creation of a hydrogen technology centre. In addition, the Residential Energy Advisory Program (REAP) was created to assist homeowners in energy conservation and electrical conversions. This part of the program, administered by Ontario Hydro and the municipal utilities, provides advice through home surveys and information, as well as financial assistance in the form of low interest loans of up to $2,000.

Reorganization of Hydro-Québec

The financial structure of Hydro-Québec has been reorganized by the Provincial Government through Bill 16 which was passed in December 1981. Under the new law, the utility has become a corporation with the Provincial Government as the sole shareholder. The law gives the Government the right to determine the level of annual dividends to a maximum of 75% of profits after interest paid on debt. Two constraints on the issue of dividends were outlined in the Bill. No payments will be made in the event that such payments would cause the equity to debt ratio to fall below 25:75, or in the event that gross interest expenditures could not be covered by net revenue from operations. The Bill also mentions a capital tax of 0.45% of total equity plus long-term debt. Hydro Québec estimates that dividend payments for 1981 will fall between $20 and $25 million, and capital tax payments, retroactive to July 1, 1981, will be approximately $43 million. A significant consequence of Bill 16 is the resultant change in the criteria used to assess rate levels. Under the new law, rates will be set in accordance with the provincial government's policies for energy conservation, taking into account the costs of other forms of energy. Previously, the utility had maintained a policy of the lowest rates possible in conjunction with sound financial policy.

ELECTRICITY NORTH OF 60°: THE YUKON AND TERRITORIES

The unusual geographic and demographic characteristics of the Yukon and Northwest Territories pose particular difficulties in the supply of electric power for these regions. Table 4 summarizes some of these factors. The Territories represent less than 0.3% of the total Canadian population but occupy 3.8 million square kilometres, about 38% of the total area of Canada. Due to the correspondingly low population densities, the electrical supply network is characterized by a large number of small generating stations and only a limited transmission network.

In 1980, electrical energy supplied about 14% of the total net (primary and secondary) energy supply in the two Territories. Thermal sources accounted for about 30% of total electrical generation, using almost 18% of the available refined petroleum products. This made electrical generation the fourth largest consumer of petroleum products in the North, and the largest consumer of diesel oil in 1980.

Electrical energy met approximately 20% of the total energy requirements in the industrial sector in 1980, 29% of commercial sector requirements and 17% of residential sector requirements. The industrial sector consumed about 49% of the electricity supply, which suggests the significance of that sector to the Territorial economies. The commercial sector consumed 25% of the electricity supply and the residential sector 26%.

There are five utilities operating in the two Territories. The largest of these is the federal Crown corporation, the Northern Canada Power Commission (NCPC), which serves 53 communities in the Northwest Territories (including 47 remote communities) and six communities in the Yukon. It owns 85% of total capacity, generates about 87% of the electricity supply and is the only non-investor-owned utility in the North. Almost 40% of its generation is sold to the other utilities. These are Alberta Power Limited (NWT), serving five communities, and its subsidiaries Yukon Electrical and Yukon Hydro which serve 18 Yukon communities; one retail distributor of electricity, Plains Western Gas and Electric Company (NWT), purchases power exclusively from NCPC. In addition, several mining companies in the Northwest Territories have their own generating capacity.

Electricity Supply and Demand

The distribution of installed capacity between utilities and industry, and generation statistics for the two Territories are detailed in Tables 5 and 6 respectively. Additional information can be obtained from Statistics Canada Publications 57-206 and 57-202. The data indicates the preponderance of diesel generation in the North, representing 62% of total installed capacity (and 28% of the total Canadian installed diesel capacity). However, diesel generation accounts for just 38% of total generation in the North. To put this in perspective, diesel generating capacity represents just 0.2% of generating capacity in southern Canada, while diesel generation represented 0.21% of total generation in 1980 in southern Canada.

Although diesel generation is the most expensive way of supplying electricity in most of southern Canada, the preponderance of small, widely scattered communities in the North have led to its heavy dependence on this type of generation. Hydro sites are often remote from the communities, and much larger than required to serve small local demands. Large capital costs prohibit the development of a transmission network to deliver the energy to the communities, including the requirements of reserve capacity which are considerably higher in the North. Diesel units have a lower capital cost than that required for hydro generation and transmission, and can be scaled to the needs of the communities, including the requirements of reserve capacity which are considerably higher in the North. In addition, diesel units have a lower capital cost and require a much shorter lead time for installation (about six months). This permitted greater flexibility in the electricity supply system, a great advantage in the North. In addition, if taken out of service, there is greater salvage value in a diesel unit than in a hydro unit.

Since about 1973 however, the costs of diesel generation have risen dramatically, from an average of $19.6 per MWh in 1970 to an average of $62.1 per MWh in 1980, a compound annual growth of 18%. This compares with the Canadian averages of $16.3 per MWh and $60 per MWh in 1970 and 1980 respectively. (The Canadian averages excluding the Territories in 1970 and 1980 were $16.1 per MWh and $59.3 per MWh respectively). It is clear from these figures that diesel fuel costs are higher in the North than in the southern areas of Canada. This is due to higher transportation and storage costs within the regions, and due to the fact that much of the oil used is imported from the south. Although there are no known oil reserves in the Yukon, reserves do exist in the Northwest Territories. The viability of increased local use of these resources is an area which has been identified for greater investigation.

These rising costs, combined with the North's heavy reliance on diesel generation (due to such factors as low water levels preventing full utilization of hydro facilities) have led to rapidly rising electricity supply costs, and to consideration of alternative sources of generation.

Due to the great distances between most northern communities, there is only a small transmission system in each Territory. In the Yukon, the total transmission circuit length is 973 km, most of this in the Whitehorse-Aishihik-Faro area. In the Northwest Territories, a total of 749 km of transmission lines have been installed, interconnecting the system around the Great Slave Lake and Inuvik. Only limited expansion of these systems is being considered.

Total generation has increased at a compound annual rate of 5.1% in the Yukon and 4.9% in the Northwest Territories

Table 4. Statistical Comparison of the Yukon and Northwest Territories

	Yukon		NWT		Canada
	Total	% of Cdn Total	Total	% of Cdn Total	Total
Population (000's)[1]	23	0.1	46	0.2	24 343
Area (000km^2)[4]	536	5.4	3 245	32.5	9 976
Density (pop/km^2)[4]	0.04	–	0.01	–	2.4
					3.9[2]
Heating Degree days[4]		7 404 (Yk + NWT combined)			4 612
Electrical Demand					
1981 (GWh)[4]	392	0.11	480	0.14	343 748
Per capita consumption of electricity (MWh)[4]	17	–	11	–	14
Electricity as % of total energy[5]		13.6		14.9	18.0
Diesel generation, as % of total generation[5]		15.7		30.8	26.1
Diesel oil used for thermal generation as % of total consumption[5]		11.6		40.1	2.5
Diesel generation as % of total energy[5]		2.1		4.6	4.7

1. *Population figures are preliminary data from Statistics Canada, 1981 census.*
2. *Density calculated excluding the Territories*
3. *Nuclear and hydro electricity converted at 10.5 MJ/kWh*
4. *SOURCE: Statistics Canada, (Degree days below 18.0 Celsius)*
5. *SOURCE Yukon: Hildebrandt – Young & Assoc., Market Forecast, Electric Energy Requirements in the Yukon Territory 1980/81 – 2000/2001, June 1981. Statistics Canada, Publication 57-003.*
   SOURCE NWT: Adelaar, Martin, Energy Demand and Supply in the Northwest Territories, February 1981.

since 1971. However, most of this growth occurred in the early part of the decade. Between 1971 and 1975 generation in the Yukon grew at a compound annual rate of 10.3%. Since 1975 however, the rate of increase has been 1.8%. Similarly, in the Northwest Territories, growth between 1971 and 1975 was 9.4% annually, but since 1975 it has averaged 2.1% per year.

Although total energy consumption by sector varies considerably between the two Territories, their electricity consumption patterns are quite similar. In both Territories the industrial sector consumes about 50% of the electricity supply, the domestic sector about 25% and the commercial sector about 25%.

The Northwest Territories' Public Utilities Board and the Electrical Public Utility Board (Yukon Territory) regulate the rates of the investor-owned companies in each Territory. The Northern Canada Power Commission, as a Federal Crown Corporation, is not legally responsible to either territorial utility board. However, rate adjustments are reviewed by the boards and recommendations from them are usually followed by NCPC.

The costs of electric power in the two Territories are among the highest in Canada. Rates in the capital cities of Yellowknife and Whitehorse are the second and fourth highest of those for major cities across the country. The electrical rates are considerably higher in those regions outside of these two cities, however there are direct and indirect subsidies which reduce these costs.

There are two direct subsidy programs in effect at this time: the Federal Power Support Program (FPSP) in effect since 1978 and the Commercial Power Rate Relief Program, implemented in March 1981 retroactive to April 1980. The two programs, directed at the domestic and small business sectors respectively, equalize some of the electricity costs incurred outside of the capital cities. The cost of the first 1000 kWh of monthly commercial consumption and the first 700 KWh of monthly domestic consumption are equalized to the costs incurred in Whitehorse or Yellowknife. Originally intended to be effective until September 1981, both programs have been extended for an additional year under the Federal Energy Policy for North of 60°, announced in April 1982. Without the subsidies many remote communities in the Territories would pay two to four times the costs incurred in remote communities in other provinces.

In a number of areas where government housing exists, electricity costs are not borne directly by the consumer, but are included in the lump-sum rental payments. Territorial governments have recently implemented programs to alter this situation and to encourage conservation in these sectors. In the Yukon, a quota system has been introduced, making tenants responsible for the payment of electrical use in excess of the quota. A similar program will be in place in the Northwest Territories in the near future.

Table 5. Installed Capacity in the Territories, December 31, 1981

	Territories	Total	APL	Indust[1]	NCPC		YEC	YH	Total
	Total	(NWT)	(NWT)	(NWT)	(NWT)	(Yk)	(Yk)	(Yk)	(Yk)
Hydro capacity (MW)	105.5	47.4	–	3.4	44.0	56.5	–	1.7	58.1
% of total hydro	100.0	100.0	–	7.1	92.9	97.2	–	2.8	100.0
number of sites	10	5	–	1	4	3	–	2	5
number of units	16	6	–	1	5	7	–	3	10
Internal Combustion capacity (MW)	168.4	132.4	11.7	16.2	104.6	27.2	8.8	–	36.0
% of total I.C.	100.0	100.0	8.8	12.2	79.0	75.5	24.5	–	100.0
number of sites	71	55	3	4	48	5	11	–	16
number of units	264	219	17	21	181	13	32	–	45
Steam capacity (MW)	0.6	0.6	–	–	0.6	–	–	–	–
% of total steam	100.0	100.0		–	100.0	–	–	–	–
number of sites	1	1	–	–	1	–	–	–	–
number of units	1	1	–	–	1	–	–	–	–
Total capacity (MW)	274.6	180.4	11.7	19.6	149.2	83.7	8.8	1.7	94.2
% of total	100.0	100.0	6.5	10.8	82.7	88.9	9.4	1.7	100.0
number of sites	82	61	3	5	53	8	11	2	21
number of units	281	226	17	22	187	20	32	3	55
% hydro capacity	38.4	26.3	0	17.3	29.5	67.5	0	100.0	61.7
% diesel capacity	61.6	73.7	100.0	59.7	70.5	32.5	100.0	0	38.3

1. Details on industrial ownership of capacity are available in Statistics Canada Publication 57-206.

NCPC – Northern Canada Power Commission; Indust – Industry; APL – Alberta Power Limited; YEC – Yukon Electrical Company; YH – Yukon Hydro Company.
SOURCE: Statistics Canada, Publication 57-206.

Future Electricity Supply and Demand

The character of Northern electricity supply and demand makes forecasts particularly difficult. Both economies depend mainly upon mining industries, thus electrical demand is determined largely by events in these areas. Similarly, the mining industry is subject to influences from outside the Territories, such as international metal prices and markets. As a result, events in mining are not easily predicted and several major development decisions are pending at the present time. The opening or closure of a mine significantly affects electrical demand. Equally, the availability of low-cost electricity plays a large part in the development of the mining sector. NCPC supplies much of the industrial load in both Territories. Hydro is generally the least expensive source of electricity, but NCPC has not chosen to develop additional hydro capacity prior to increases in demand. This is largely due to its mandate, set out in the NCPC Act of 1956 and amended in 1975, which dictates that the Commission provide electrical service on a cost recovery basis. It therefore cannot finance excess capacity. The lengthy lead time involved in hydro capacity makes the coordination of its availability and industrial development difficult. In addition, the uncertain lifetime of industrial loads can make hydro development uneconomical. As a result, much industrial demand has been met, at least initially, by additional diesel capacity.

At the present time, the Northern Canada Power Commission is the only utility authorized to develop hydro resources in the North. This authorization stems from a 1974 policy directive issued by the Minister of Indian Affairs and Northern Development. The legality of this directive may, however, soon be challenged. The Yukon Electrical Company has applied to the Yukon Water Board for a water license to construct and operate the McIntyre Creek project, a $2.5 million small hydro plant (0.7 MW) for the Takhini area of Whitehorse. Ratification at the Federal level will be required if the license is granted by the Yukon Government. Other proposed capacity additions are indicated in Table 7.

The Northern Canada Power Commission conducts a series of electrical demand forecasts on an annual basis. The results of the 1980/81 studies indicate little growth in demand in the Yukon up to 1984. The trend after that time is uncertain. An increase would stem predominately from stronger markets for minerals, and the availability of natural gas. A decrease in electrical demand would result from a curtailing of mining activity and a decision against the development of natural gas potential.

In the Northwest Territories, electrical demand growth is expected to be greatest in isolated communities. Both the domestic and commercial sectors are expected to experience comparatively

Table 6. Generation in the Territories, 1971-1981

	Total Generation			NCPC			YEC		YHC		Industry	
Yukon	GWh	% hydro	% diesel	hydro (GWh)	diesel (GWh)	% of total	diesel (GWh)	% of total	hydro (GWh)	% of total	diesel (GWh)	% of total
1971	238	80	20	181	11	81	10	4	10	4	26	11
1975	352	73	27	247	49	84	15	4	11	3	30	9
1979	357	89	11	308	25	93	15	4	9	3	0	0
1980	382	84	16	314	43	94	17	4	7	2	0	0
1981[1]	392	74	26	N/A	N/A	94	N/A	N/A	N/A	N/A	0	0

	Total Generation			NCPC			APL		Industry		
N.W.T.	GWh	% hydro	% diesel	hydro (GWh)	diesel (GWh)	% of total	diesel (GWh)	% of total	hydro GWh)	diesel (GWh)	% of total
1971	297	72	28	211	56	90	14	5	2	14	5
1975	425	64	36	246	111	84	25	6	25	19	10
1979	486	58	42	260	134	81	26	5	22	44	14
1980	494	59	41	268	133	81	26	5	24	43	14
1981[1]	480	52	48	N/A	N/A	80	N/A	N/A	N/A	N/A	5

	Total Generation			NCPC			Investor-owner Utilities			Industry		
Yukon and N.W.T. Total	GWh	% hydro	% diesel	hydro (GWh)	diesel (GWh)	% of total	hydro (GWh)	diesel (GWh)	% of total	hydro (GWh)	diesel (GWh)	% of total
1971	535	76	24	392	67	86	10	24	6	2	40	8
1975	777	68	32	493	160	84	11	40	7	25	49	10
1979	843	71	29	568	159	86	9	41	6	22	44	8
1980	876	70	30	582	176	87	7	43	6	24	43	8
1981	872	62	38	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

[1] *Preliminary Data*
N/A not available
SOURCE: Statistics Canada Publication 57-202

Table 7. Proposed Capacity Additions in the Yukon and Northwest Territories

Owner	Location	Capacity	Source
NCPC	Whitehorse, Yk	20 MW	hydro
Yukon Electrical	McIntyre Creek, Yk	0.7 MW	hydro
	Watson Lake, Yk	1.5 MW	waste wood
Industry	Yukon	5,0 MW	thermal
	Norman Wells, NWT.	unspecified	natural gas
	Tuktoyaktuk, NWT	unspecified	natural gas

little growth in demand. Growth in the industrial sector is again dependent upon international events in the metals market, as well as the outcome of such projects as the construction of the Alaska Gas Pipeline Dempster Lateral and the Norman Wells crude oil pipeline.

The alternatives to diesel generation vary significantly from region to region in the two Territories, but consist primarily of wind, coal, natural gas, small hydro and biomass. Surveys of the theoretical hydro development potential in the Territories have identified as many as 180 sites, ranging in size from 5 MW to as much as 4 850 MW. However, the relatively low electrical demand in most communities makes the development of large scale hydro projects uneconomical in the majority of cases. The development of small hydro capacity, that is capacity of less than 15 to 20 MW, has been constrained by the initial high capital expenditures required. However, the increasing cost of diesel fuel has resulted in reassessments of their economic viability. Although a number of surveys of the theoretical small hydro potential in the North have been carried out, few comprehensive economic analyses have been undertaken.

Atomic Energy of Canada is developing a larger version of its Slowpoke nuclear reactor (Safe Low Power Critical Experiment) for possible application in remote northern communities. It is expected that the $2.1 million 2 MW reactor will be available by 1985, following initial testing at AECL's Chalk River laboratories.

In addition to the development of renewable energy options, more efficient use of existing diesel generation facilities, such as the development of waste heat recovery systems, is also being encouraged. The Northern Canada Power Commission currently operates major residual heat recovery systems at four cities: Dawson City, Yukon; Cambridge Bay, Igloolik and Rankin Inlet in the Northwest Territories. The utility hopes to further develop these systems in other northern communities, but has been hindered by the initially high capital costs involved. In addition, Alberta Power has undertaken a feasibility study of a waste heat recovery system in Hay River.

Federal and Territorial Policies

The problems of energy supply in the North have been receiving increased attention. A Parliamentary Subcommittee on NCPC was established in March 1981 to investigate its electrical power costs, rate structures, mbde of operation and means of regulation. Its recommendations concerned the possible reorganization of NCPC to increase its responsibility to the respective Territorial Governments, as well as proposals for alternative financing arrangements and more integrated electrical and total energy forecasts.

Recommendations from the recently completed Northern Energy Task Force study largely contributed to the development of the Federal Energy Iniatives Program for North of 60°. This $19 million package of programs is concerned with the overall energy situation in the North, and focuses upon the conservation of energy, efficient use of diesel generation, as well as the investigation of alternative energy and electrical resources.

Of particular relevance to the supply and demand for electricity are the extension of subsidized electrical rates, discussed in a previous section, and modifications to COSP, effective in August. Under the new guidelines, conversions from diesel generated electric space heating are now eligible for the $800 taxable grant. These grants will now be available to public and community housing units in addition to private units.

Another feature of the North of 60° Initiatives is the Remote Community Demonstration Program (RCDP). It has been created to assess energy conservation options and local energy supplies to replace the existing reliance upon oil. This program should encourage the development of alternative small-scale generation facilities. It is designed in two phases, to assess energy options and then to implement selected demonstration projects.

In addition, the Conservation and Renewable Energy Development and Demonstration Agreements (CREDA) has been reinforced. This program includes projects to encourage conservation as well as projects for waste heat recovery from diesel generators and demonstrations of wood, wind, and small hydro uses. Agreements with the Territorial Governments have been reached for a total of 16 projects in the Yukon, and 10 projects in the Northwest Territories.

Finally, the Distribution System Expansion Program (DSEP), announced in March 1982, is applied to the North to assist the investigation of potential markets for natural gas and propane. Natural gas is seen as a possible source of fuel for electrical generation, as well as serving as a substitute to electricity in some applications.

In addition to this set of initiatives, a number of energy-related programs already exist in the North. For example, under the Federal Government, the Arctic Housing Standards and the Canadian Home Insulation Program focus on different aspects of energy conservation in the North.

The two Territorial Governments have also implemented a variety of conservation and oil substitution initiatives. Programs exist in the Northwest Territories to assist the development of projects using renewable energy resources such as wood and solar. The Northwest Territories government is implementing the use of wood gasification and solar technologies in Fort Providence. The Yukon government is investigating the potential for wind generation; a wind monitoring device has been installed near Destruction Bay as part of these studies. Both Territories have initiated large scale public awareness campaigns to educate the public in conservation methods, as well as instigating a number of programs to

encourage conservation in public buildings.

Development in the North must address specific concerns which are less apparent in other areas of Canada. The northern lifestyle in particular is radically different from its southern counterpart. Issues such as native land claims and the preservation of native culture are variables not encountered in most of the rest of the country. In the selection of alternative energy sources, these factors must be weighed as well as economic considerations.

The environment also poses specific technological difficulties. There are much greater variations in temperature which create additional stress on equipment. The presence of permafrost requires modifications in construction and design. The inaccessibility of many communities for large parts of the year impose greater requirements for storage and reserve capacity.

There are at least 60 remote communities in the two Territories which depend on diesel capacity. As expansion of the electrical transmission network is limited, the development of community-specific alternatives to diesel will be a long procedure. However, this process should do much to alleviate the many problems and concerns of electricity supply in the two Territories.

ELECTRICITY USED FOR SPACE AND WATER HEATING

The amount of electricity used for space and water heating in the future will have an important bearing on the demand for electricity. This is so because energy used for these two functions comprise by far the largest amount of energy used in the residential and commercial sectors of the economy. The purpose of this section is to set out some background on space and water heating in the residential sector during the past ten years, and to provide a look at what can be expected during the 80's.

Background

The degree to which electricity is used in each province for space and water heating depends essentially on the relative price of gas, oil and electricity plus the availability of gas. Gas is not available in the Atlantic Region, in many parts of Quebec and in some parts of the other provinces, so the principal choices for water and space heating in those regions have been electricity and oil.

Data in Table 8 indicates that the use of oil for residential water heating has declined slightly during the period, with the gas and electricity percentages increasing. In the only two provinces where the electricity percentage has declined, gas has increased its percentage.

The percentage of total households in Canada that are using electricity for water heating has remained quite constant during the past ten years while the percentage using oil has declined slightly and the percentage using gas has increased slightly. However, there have been some quite significant changes in the principal fuel use in some Provinces. For example, in Newfoundland and New Brunswick, the percentage using electricity has increased significantly over the period.

Data in Table 9 indicates that the percentage of total households using oil for space heating has declined significantly during the period, from 57% of the total in 1970 to 37% in 1980. The percentage using gas has increased modestly from 34% to 40%, while the percentage using electricity has increased significantly, from 5% to 19%. Those provinces with the largest increase in electricity use for space heating are Newfoundland, New Brunswick and Quebec. In Newfoundland and New Brunswick there is no gas available, while in Quebec it has been available only in the Montreal area. In each of these provinces there is a strong hydro generating base that has resulted in a less rapid increase in electricity prices relative to increases in Nova Scotia and P.E.I., the other provinces which do not have gas available.

The penetration rate of electricity as a principal heating source for new households in each province is shown in Table 10 for 1970 to 1980. As could be expected from the foregoing paragraph, the penetration rate is strongest in Newfoundland, New Brunswick and Quebec.

The Future

Utility estimates of the use of electricity as the principal energy source for space and water heating in new households in the 80's are shown in Table 11. In addition it is expected that there will be a significant number of conversions to electricity of heating systems in existing households, mainly from oil.

It is expected that new households will mainly use gas or electricity for their principal space and water heating requirements. This direction is indicated by the high and rapidly increasing cost of oil, and by government financial incentives to use non-oil energy sources. Electricity is expected to become an increasingly attractive alternative relative to gas over the decade, since electricity prices are expected to increase more slowly than gas prices; energy efficient households will require less energy, perhaps significantly less, increasing the unit delivery cost of gas and influencing the use of electricity as a single energy source. Improvements in heat pump technology will encourage its use for air conditioning and heating loads.

Existing households that use gas for space heating tend to use it also for water heating. However, it is possible that electricity will be used increasingly for water heating in the future, even in those households using gas for space heating, because new high efficiency gas furnaces do not require a chimney, which prevents the use of conventional gas water heaters.

Table 8. Percentage Use of Each Energy Type for Water Heating

	1970			1975			1980		
	Oil	Gas	Electricity	Oil	Gas	Electricity	Oil	Gas	Electricity
Newfoundland	55	–	40	43	–	56	24	–	74
Prince Edward Island	65	–	20	63	–	27	64	–	29
Nova Scotia	46	–	42	48	3	45	52	5	40
New Brunswick	54	4	36	49	3	46	36	–	61
Québec	22	10	67	24	7	68	16	6	78
Ontario	5	37	58	5	41	54	4	44	52
Manitoba	–	52	46	–	53	45	–	53	45
Saskatchewan	–	67	30	–	69	28	–	69	31
Alberta	1	95	4	–	95	5	–	95	5
British Columbia	13	38	48	13	42	45	8	50	42
CANADA	13	34	52	14	35	51	10	37	53

Note: Percentages may not total 100 for each province, since not all energy sources are included.

Source: Table 17, Statistics Canada Publication 64 – 202

Table 9. Percentage Use of Each Energy Type for Space Heating

	1970			1975			1980		
	Oil	Gas	Electricity	Oil	Gas	Electricity	Oil	Gas	Electricity
Newfoundland	85	–	–	78	–	17	53	–	34
Prince Edward Island	92	–	–	93	–	–	85	–	–
Nova Scotia	83	–	2	86	–	6	79	–	0
New Brunswick	87	–	–	86	–	8	63	–	25
Québec	81	8	7	75	7	15	53	6	38
Ontario	54	39	5	47	42	10	35	48	14
Manitoba	32	59	4	25	59	14	16	61	19
Saskatchewan	33	64	–	23	74	–	21	74	3
Alberta	6	90	–	4	94	–	2	97	1
British Columbia	48	42	7	42	46	11	25	55	16
CANADA	57	34	5	52	36	10	37	40	19

Note: Percentages may not total 100 for each province, since not all energy sources are included.

Source: Table 17, Statistics Canada Publication 64 – 202

Table 10. Historical Penetration Rate of Electricity for Space Heating in New Households (%)[1]

	1970	1972	1974	1976	1978	1980
Newfoundland	10.9	27.0	64.4	71.5	60.5	59.4
Prince Edward Island			Negligible			
Nova Scotia	N/A	16.0	53.5	27.2	11.7	39.0
New Brunswick	9.7	14.6	19.3	N/A	55.0	55.0
Québec	N/A	48.4	57.8	64.3	77.0	84.0
Ontario	18.0	25.1	24.0	31.0	27.8	21.6
Manitoba	25.2	30.3	32.8	61.3	43.6	42.6
Saskatchewan	–	–	–	–	–	–
Alberta			Negligible			
British Columbia	13.3	15.1	22.4	43.1	48.4	40.1

[1] Based on information obtained from major electric utilities

N/A not available

Table 11. Forecast Penetration Rate of Electricity for Space and Water Heating in New Households (%)[1]

	1980		1982		1984		1986		1988		1990	
	S	W	S	W	S	W	S	W	S	W	S	W
Newfoundland	59	80	68	82	76	84	80	86	80	88	80	90
Prince Edward Island	Neg	30	–	30	–	30	–	30	–	30	–	30
Nova Scotia						not available						
New Brunswick[4]	60	80	60	80	60	80	38	56	38	56	38	56
Québec	80	87	80	87	80	87	85	88	85	88	85	88
Ontario	22	25	26	29	38	40	45	45	50	50	55	55
Manitoba	36	45	46	45	38	45	37	45	37	45	36	45
Saskatchewan						Only nominal penetration						
Alberta[2]						Negligible						
British Columbia[3]	40	50	42	50	42	50	31	40	31	40	31	40

S – Space heating
W – Water heating

[1] For the areas served by major electric utilities in each province, based on information obtained from the utilities.

[2] The utility estimate is for negligible electricity use for space or water heating, the penetration rate shown is an EMR estimate.

[3] Assumed availability of natural gas on Vancouver Island after 1984 covers the decreased electricity penetration. B.C. policy is to price electricity at 80% of the electricit,' cost.

[4] Assumes natural gas available after 1984.

Electrical generation from fuel sources represented 30% of the total supply in 1981. Preliminary data indicates that 16% of production was from coal-fired stations, an increase of 7.5% over 1980. Both oil and gas use declined once again in 1981, representing 2.4% and 1.8% respectively of total generation. As a result, total generation from conventional thermal sources declined 3% in 1981. Nuclear generation increased 5% from 35 880 GWh in 1980.

It can be seen from Table 12 that Ontario was clearly the largest user of fuels for electricity production in 1980, accounting for almost 62% of the total. Alberta was the second largest user, accounting for 19% of the total. When only fossil fuels are considered, Ontario accounted for 39% of the total, and Alberta 30%. Ontario remained the largest user of coal in 1980, and New Brunswick the largest user of oil. Total oil use declined by almost 5.8% from 1979 while the total amount of coal used increased 11.7% from 1979. The quantity of gas used for electrical generation declined 9.9% from 1979 while growth in Ontario's nuclear generation increased uranium use by 14.4%.

Ontario imported almost 80% of its coal requirements from the United States in 1980; the remainder of the coal used was from Western Canada. The coal used by Manitoba was imported from Saskatchewan, while Alberta, Nova Scotia and New Brunswick use their own coal resources. Saskatchewan relies primarily on its own coal, but imports some additional resources from Alberta.

All of the oil used by the Atlantic Region and Quebec is imported from outside Canada. Ontario uses Canadian oil, primarily residual. In the Territories, Canadian diesel oil is used. The natural gas and uranium used in Canada are from domestic sources; natural gas from western Canada and uranium from Ontario and Saskatchewan.

Regional patterns of fuel use for electricity generation are changing. Since 1979, the quantity of oil used by utilities has decreased in three provinces. In Nova Scotia, Prince Edward Island and Ontario, the reductions were 12%, 14%, and 78% respectively. Ontario has also reduced the amount of natural gas used, down 70% from 1979 levels. Coal use increased substantially in three provinces,

more than doubling in Manitoba and Nova Scotia, and up to 59% in New Brunswick.

Table 12. (a) Fuel Use by Utilities, 1980

Province	Coal	Oil	Gas	Energy Content	Percentage of total
	(10^3 tonnes)	(10^3 kL)	10^6 m^3	(10^3 TJ)	(%)
Newfoundland	–	392	–	16	2.0
Prince Edward Island	–	54	–	2	0.2
Nova Scotia	1 057	738	–	59	7.4
New Brunswick	315	1 371	–	66	8.3
Québec	–	119	–	5	0.6
Ontario	10 811	61	134	315	39.4
Manitoba	220	17	–	5	0.6
Saskatchewan	4 972	12	214	78	9.8
Alberta	10 410	3	1 338	243	30.4
British Columbia	–	30	189	8	1.0
Yukon	–	18	–	1	0.1
NWT	–	52	–	2	0.2
CANADA	27 785	2 867	1 875	800	100.0

SOURCE: Statistics Canada, Publication 57-202

TABLE 12. (b) Fuel Use by Utilities, 1980

Province	Coal	Oil	Gas	Uranium	Total	% of total
		(10^3 TJ)				
Newfoundland	–	16	–	–	16	1.3
Prince Edward Island	–	2	–	–	2	0.2
Nova Scotia	28	31	–	–	59	4.6
New Brunswick	9	57	–	–	66	5.2
Québec	–	5	–	–	5	0.4
Ontario	308	2	5	470	785	61.8
Manitoba	4	1	–	–	5	0.4
Saskatchewan	70	–	8	–	78	6.1
Alberta	191	–	52	–	243	19.1
British Columbia	–	1	7	–	8	0.6
Yukon	–	1	–	–	1	0.1
NWT	–	2	–	–	2	0.2
CANADA	610	118	72	470	1270	100.0

SOURCE: Statistics Canada, Publication 57-202

FORECAST ELECTRICITY DEMAND, PRODUCTION AND CAPACITY

This section provides an overview of the forecast electricity demand, source of production, and installed generating capacity for Canada. Additional quantitative information can be found in Tables A6 and A7.

Forecast Demand

In Figure 5 it is clear that there has been a close historical relationship between per capita economic performance, as measured by Gross National Product (GNP) and per capita electricity demand. Since per capita economic growth and population growth over the next twenty years is forecast to be significantly lower than was experienced over the past twenty year period, it is expected that electricity growth will be lower as well. Table 13 provides an indication of growth in the period 1960-1980 of real GNP (i.e. GNP net of inflation), population, primary energy demand (i.e. the total energy available from the energy sources as they exist in their original state) and electrical energy demand, as well as the forecasts for each of these items for the period 1980-2000. It is evident from this table that electrical energy is expected to play an increasingly large role in energy supply in Canada in the future. The percentage of primary energy supplied in the form of electricity is expected to increase from the 38% of 1981 to about 43% in 1990 and 48% in 2000.

Recent government initiatives are expected to increase electricity demand.

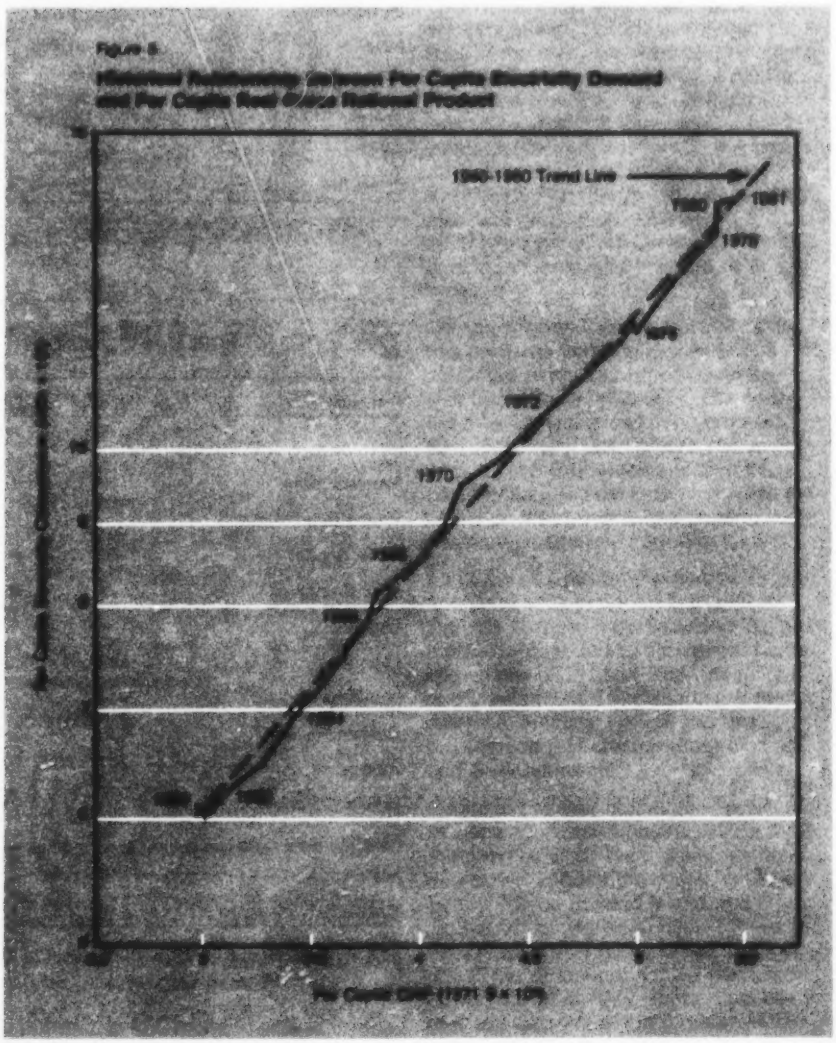
Table 13. Historical and Forecast Annual Growth Rates For Real GNP, Population, Primary and Electrical Energy

	1960 – 1980	1981 – 2000
Real GNP	4.5	3.0
Population	1.46	0.8
Primary Energy	4.5	2.4
Electrical Energy	5.8	3.5

SOURCE: Energy, Mines and Resources, Energy Demand Forecasting Model.

The National Energy Program introduced by the Federal Government in October 1980 included financial incentives to switch from use of oil to non-oil sources of energy. The primary substitutions are expected to be gas and electricity. Nearly half of the conversion projects receiving government financial assistance are for changes to electricity. This program was reinforced in Ontario in the spring of 1981 when the Ontario government introduced a program to encourage the use of electricity as a substitute for other energy forms.

It has been very difficult to forecast electricity demand throughout the last half of the 1970's, mainly because of the very rapid rise of energy prices induced by oil price increases. These increases have caused a considerable amount of adjustment in world economies. Major adjustments have been made in the amounts and ways in which energy is used, as well as in the type of energy used. This continuing adjustment process makes forecasting of economic development very uncertain. Given the close relationship between economic develop-



ment and electricity demand noted above, the economic uncertainty leads to uncertainty in future electricity demand.

The ways and the extent to which consumers will respond to higher energy prices is cause for further uncertainty, as is the future level of world oil prices. Energy consumers have already reacted to higher energy prices by reducing the amount of energy used, by conservation measures that permit more efficient use of energy, by lifestyle changes that require less energy, and by changing the types of energy used. World oil prices have fluctuated in real terms quite considerably since 1973. The sharp price rise in 1973 was followed by four years of reasonably steady prices. But, in 78/79 price increases were larger than those of 1973. These increases were followed by declining prices in 1981 which became quite marked in early 1982. The future pattern of world oil prices is similarly uncertain.

In spite of the inherent uncertainties of the times, the long (5-10 years) lead times required to bring new generation facilities into service requires that forecasts be prepared of future demand. The forecasts of what the utilities consider to be the most probable rate of electricity demand growth as of January 1982 are provided below, in terms of average annual percentage growth.

	1981-1990	1981-2000
	(%)	
Canada	4.9	4.2
Newfoundland	7.3	6.0
Prince Edward Island	2.0	2.3
Nova Scotia	3.3	3.1
New Brunswick	3.3	2.8
Québec	5.1	4.6
Ontario	3.8	3.2
Manitoba	4.0	3.3
Saskatchewan	5.5	3.7
Alberta	7.3	6.0
British Columbia	6.2	4.9
Yukon, N.W.T.	6.5	5.6

These forecasts of average annual growth show a modest decline from the forecasts of last year in nearly all provinces. However, the Québec forecast has shown a significant drop from the 1980-2000 average annual growth of 6.0% last year to the 4.6% currently forecast. This is the result of expected increased use of natural gas, lower economic growth and increased saturation of electrical appliances.

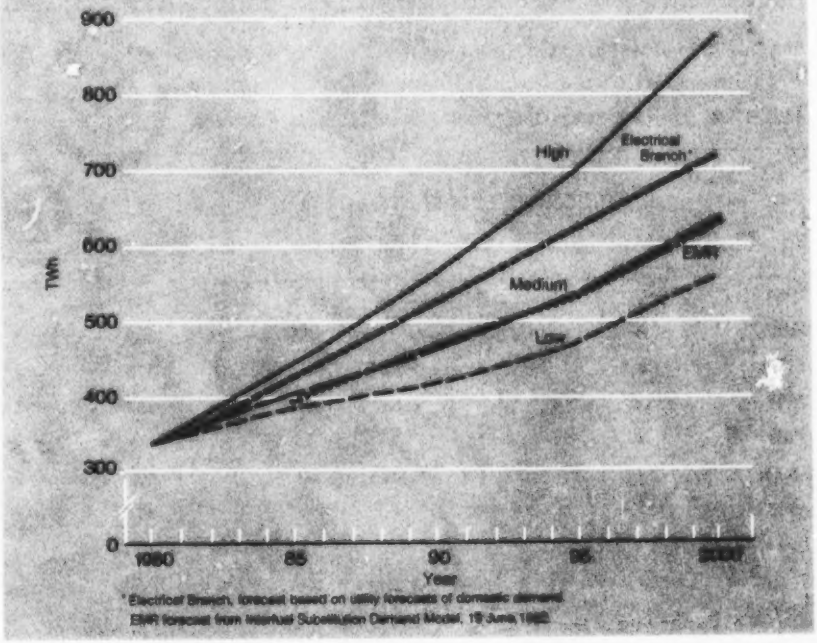
Figure 6 illustrates that the National Energy Board 1981 median (most probable) forecast of electricity demand for Canada is very similar to the EMR forecast. Included on the graph for comparison is the electricity demand forecast developed by the Electrical Branch of EMR, based on forecasts provided by the major utilities and total electricity demand in each province. It may be noted that the utility based forecast of electricity demand is somewhat higher than the NEB/EMR most probable forecast. This is a normal situation, since the utilities must provide facilities to meet expected demand, and the cost of under capacity through curtailed economic activity is greater than that of over capacity. The tendency is, therefore, to err on the high side.

In view of the very uncertain conditions which exist, forecasts of electricity demand have a higher than usual degree of uncertainty. In these circumstances, it is necessary to develop expected high and low forecasts, as well as a most probable forecast used for system planning purposes.
Development is required in the area of flexible expansion programs which are designed to meet the most probable forecast, but which can be readily adjusted to the evolving conditions.

Forecast Production and Capacity

The present and forecast future sources of generation capacity and production are shown in Table 14. This indicates that oil and gas use for electricity generation, at present only a small portion of the total, will continue to decline relative to the total over the period, but will increase slightly in absolute terms. As a percentage of the total generation, oil and gas will be used as the source of about 3% in 2000 compared to 5% in 1981. Coal, uranium and hydro will be the major sources of electricity generation and are expected to substitute for much of the present oil-fired generation in the Atlantic Region

Figure 6
Electrical Energy Demand Forecast



* Electrical Branch, forecast based on utility forecasts of domestic demand
EMR forecast from Market Substitution Demand Model, 15 June 1982

during the next twenty years. Most of the remaining oil generation will take place in Ontario and Quebec, for peaking purposes, and in some remote communities in the North.

Table A6 suggests that between 1981 and 1994 a total of 34 127 MW are expected to be added to capacity. More than half of this total will be in hydro additions (18 808 MW). The next largest expansion is expected to be in nuclear capacity, with 9 927 MW to be added by 1994, 29% of total additions. This will almost triple the 1981 installed nuclear capacity. Coal additions are expected to be 5 235 MW or about 15% of the total. Gas-fired capacity is expected to decrease over this period, while oil-fired capacity will remain at about its present level. Much of the gas-fired capacity is in Alberta where a significant amount will be displaced by coal additions which produce electricity at a lower cost.

It is likely that the forecast mix of future generation will be reliable. However, the actual additions for a given future year may require upward or downward adjustment to match future experience in economic performance and other factors affecting total energy and electricity demand.

Table 14. (a) Forecasts of Generating Capacity by Type, Canada

	(GW) Conventional Thermal							Percentage of Total Capacity					
Year	Oil	Gas	Coal	Total	Nuclear	Hydro	Total	Oil	Gas	Coal	Total Conventional Thermal	Nuclear	Hydro
1981*	8.0	4.5	16.0	28.5	5.6	49.7	83.8	10	5	19	34	7	59
1982	8.1	4.9	15.9	28.9	6.2	51.1	86.2	9	6	19	34	7	59
1983	8.2	4.6	16.2	29.0	8.7	52.7	90.4	9	5	18	32	10	58
1984	8.2	4.5	17.3	30.0	10.5	56.0	96.5	8	5	18	31	11	58
1985	8.3	4.5	17.9	30.7	10.5	58.7	99.9	8	5	18	31	10	59
1990	10.6	3.7	20.7	35.0	15.5	66.7	117.2	9	3	18	30	13	57
1995	10.9	3.9	22.3	37.1	17.2	80.4	134.7	8	3	17	28	13	60
2000	11.3	3.9	24.2	39.4	19.2	96.6	155.2	7	3	16	26	12	62

* *Actual.*
SOURCE: Department of Energy, Mines and Resources, based on forecasts provided by Utilities and the National Energy Board.

Table 14. (b) Forecasts of Production by Source, Canada[1]

	(TWh) Conventional Thermal							Percentage of Production					
Year	Oil	Gas	Coal	Total	Nuclear	Hydro	Total	Oil	Gas	Coal	Total Conventional Thermal	Nuclear	Hydro
1981*	7	10	56	73	38	232	343	2	3	16	21	11	68
1982	8	11	66	85	36	240	361	2	3	18	23	10	67
1983	8	11	65	84	45	247	376	2	3	17	22	12	66
1984	8	11	63	82	61	254	397	2	3	16	21	15	64
1985	7	12	70	89	63	263	415	2	3	17	22	15	63
1990	10	16	73	99	96	313	508	2	3	14	19	19	62
1995	11	18	92	121	114	369	604	2	3	15	20	19	61
2000	12	13	102	127	138	441	706	2	2	14	18	20	62

1 To satisfy electricity demand in Canada. Does not include exports to the United States.
* *Actual.*
SOURCE: Department of Energy, Mines and Resources, based on forecasts provided by Utilities and the National Energy Board.

EXPORTS AND IMPORTS

International

Electricity exports in 1981 represented 9% of net generation in Canada, while imported electricity accounted for less than 1% of total demand. Net exports to the United States increased by about 24% during l981, to a total of 33 875 GWh. This resulted from exports of 35 372 GWh and imports totalling 1 497 GWh. This was up from 7% in 1980 and represents an all time high in net exports.

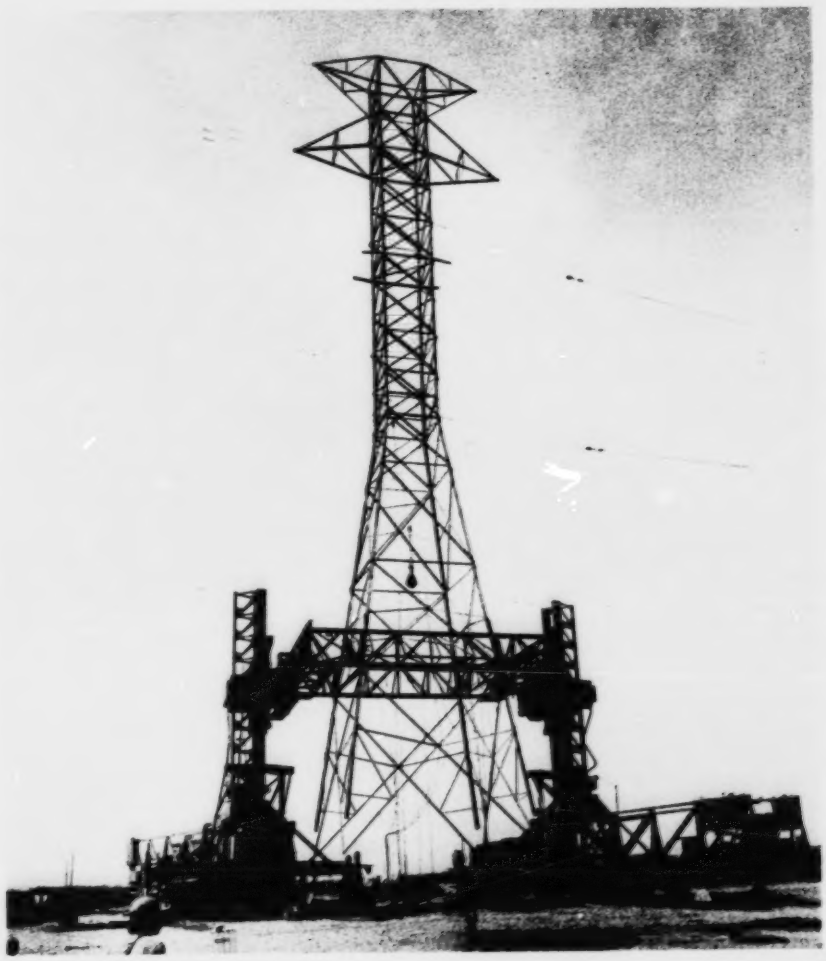
Three provinces registered increases in net exports during l981. In Manitoba and Quebec these increases were negligible at 4.5% and 2.5% respectively. However, British Columbia's net exports in 1981 were over seven times as large as 1980 levels, reaching 7 924 GWh from 1980's total of 913 GWh. This growth is attributable to unusually high precipitation during the year, resulting in an estimated 22% increase in growth of hydro generation, coupled with the demand for the energy to displace oil-generated electricity in the United States.

Net international exports declined by 16.5% in New Brunswick. This resulted from a change in an agreement which the province has with a group of U.S. utilities. The portion of N.B. Power's Coleson Cove plant, for which the U.S. utilities cover the fixed costs, was reduced to 133 MW from 400 MW.

While net exports increased significantly in 1981 alone, it is evident from Table 15 that both the amount of energy exported to the U.S. and the revenue received have increased substantially in the five year period from 1977. The major reasons for increased exports are periods of inadequate supply in the U.S., and displacement in the U.S. of high-cost electricity generated from oil by imports of relatively low-cost electricity. Canadian exports of electricity have been generated primarily from hydro and coal, with comparatively small amounts generated from oil and nuclear. This distribution is expected to continue in the future with the majority of export licenses, described in the section "Developments in 1981", stemming from hydro and coal generation. The major exception is the New Brunswick license which will be the first nuclear power export contract.

There are about 30 Canada-U.S. interconnections of 69 kV or over, with a power transfer capacity of about 10 000 MW. There were no additions to interconnection capacity during 1981 (Table 16). The 230 kV interconnection between Saskatchewan and North Dakota will be commissioned in May of 1982. An application by the Nebraska Public Power District (NPPD) for a transmission link with Manitoba was denied by the South Dakota Public Utilities Commission. However, pending further action by NPPD, Manitoba Hydro is still prepared to meet an in-service date in the late 1980's.

Planned or proposed additional or upgraded interconnections between Canada and the U.S. are indicated in Table 17. In addition, Hydro Québec expects to have a 1000 MW high voltage direct current convertor station at Chateauguay in service by 1984. This will permit the utility greater flexibility in transmission interconnection for both exports and imports. For example, importing 500 MW during peak winter periods will reduce the proposed gas turbine peaking units by a like amount. Hydro Quebec is



Ontario Hydro staff designed a tower lifting machine which permits towers to be raised to install heavier conductors while keeping the existing conductors in service.

negotiating with New England utilities for a 600 MW interconnection, expected to be in service for 1986.

In 1981, a number of applications for electricity exports were filed with the National Energy Board. The New Brunswick Electric Power Commission applied to export a total of 335 MW from the Pt. Lepreau nuclear plant to five utilities in Maine and Massachusetts. The firm power contracts would extend to 1990 and 1995. A decision is expected early in 1982.

Hearings were conducted in January 1982 on Ontario Hydro's application to export about 1000 MW of firm power to General Public Utilities Limited (GPU) of New Jersey. The proposal involves a 1200 MW HVDC cable interconnection under Lake Erie to Pennsylvania. The export contract would be in effect from 1985 to 1995 and the utility's Nanticoke coal-fired thermal generating station would supply most of the power.

Ontario Hydro obtained approval for a new double circuit 345 kV interconnection with the Power Authority of the State of New York (PASNY), at Niagara. The in service date is scheduled for February 1984. In August 1981, sale of the entire output of the 254 MW J.C. Keith generating station to GPU commenced. The contract extends for a three year period.

In the fall, Quebec invited the New England States to make the province an offer for purchase of surplus hydro power on a long-term basis. The power could include not only surplus expected to be available by the mid-1980's from Quebec's James Bay project, but also construction of new capacity primarily for export as base load. This move represents a shift in Quebec government policy, since the province has in the past declined to provide firm power under a long-term contract, nor would it build capacity for export.

Interprovincial

Good water conditions in both British Columbia and New Brunswick contributed to increases in interprovincial exports of 65% and 42% respectively. Increases were also reported by Saskatchewan and Ontario of 12% and 20% respectively. Drought conditions in Manitoba resulted in a 12% increase in interprovincial imports while reduced thermal generation in Nova Scotia contrib-

Table 15. International Electricity Trade, 1977-1981

	1977	1978	1979	1980	1981
			(GWh)		
Exports [a]	18 509	20 542	30 491	28 229	34 730
Imports [a]	1 060	185	24	169	466
Net Exports	17 449	20 357	30 467	28 060	34 264
Generation source for exports: [b]					
Hydro	5 738	6 984	14 941	12 336	19 948
Imported Coal	8 514	10 476	11 587	10 599	10 901
Imported Oil	2 961	2 260	3 354	2 867	1 940
Canadian Fossil Fuels: (coal and oil)	555	411	128	593	665
Nuclear	–	–	177	30	42
Other [c]	740	411	305	1 804	768
TOTAL	18 509	20 542	30 491	28 229	34 264
Revenue/cost			(million $)		
Exports	419.27	478.55	738.51	793.58	1 143.87
Imports	13.13	1.76	0.70	2.94	5.62
Net Revenue	406.14	476.79	737.81	790.64	1 138.25

(a) Excludes no-value exchanges.
(b) Estimated from data for major utilities.
(c) Includes purchases for export where the generation source is unknown.

SOURCE: National Energy Board

Table 16. Major[1] Interconnections Between Canada and the United States

Province[2]	State	Voltage	Power Transfer Capability
		(kV)	(MW)
New Brunswick	Maine	345	500
Québec	New York	765	1400
	New York	2 × 120	200
	Vermont	120	100
Ontario	New York	230	470
		230	400
		2 × 230	600
	Michigan	230	535
		230	515
		345	710
		345	760
Manitoba	North Dakota	230	150
	Minnesota	230	175
	Minnesota	500	1000
British Columbia	Washington	230	350
		230	300
		2 × 500	1400

1. 100 MW capacity or over.
2. *Installed interconnections; simultaneous transfer capability can be considerably less.*

uted to an 84% increase in imports, returning the province to a net import position. These interprovincial exchanges are outlined in Table A5.

There were no additions to the existing interprovincial interconnections, given in Table 18. Negotiations concerning the proposed interconnections in Table 19 continued during 1981. One of these is the Western Power Grid being discussed by the three Prairie provinces. Negotiations have been delayed to allow the new Manitoba and Saskatchewan Governments to examine the viability of this proposal. Originally, a 35-year agreement was planned during which time Manitoba would supply Saskatchewan with 500 MW and a further 1000 MW to Alberta, to be generated from newly constructed hydro-electric stations. The interconnection, now narrowed to a choice of 3 routes, would entail some 1 700 km of transmission lines and would cost an estimated $1 billion. A final decision is not expected before the end of 1982. In addition, the 500 kV interconnection under construction between Alberta and British Columbia is now scheduled for completion in 1984.

In eastern Canada, New Brunswick and Quebec continue to negotiate strengthened interconnection between the two provinces consisting of two new lines with a capacity of about 500 MW; expected to be in service in 1986.

During 1981 Ontario Hydro agreed to purchase 12.5 billion kWh from Quebec for the period 1982 to 1987. The price was based on the cost of producing the energy at Ontario's Lakeview coal-fired station.

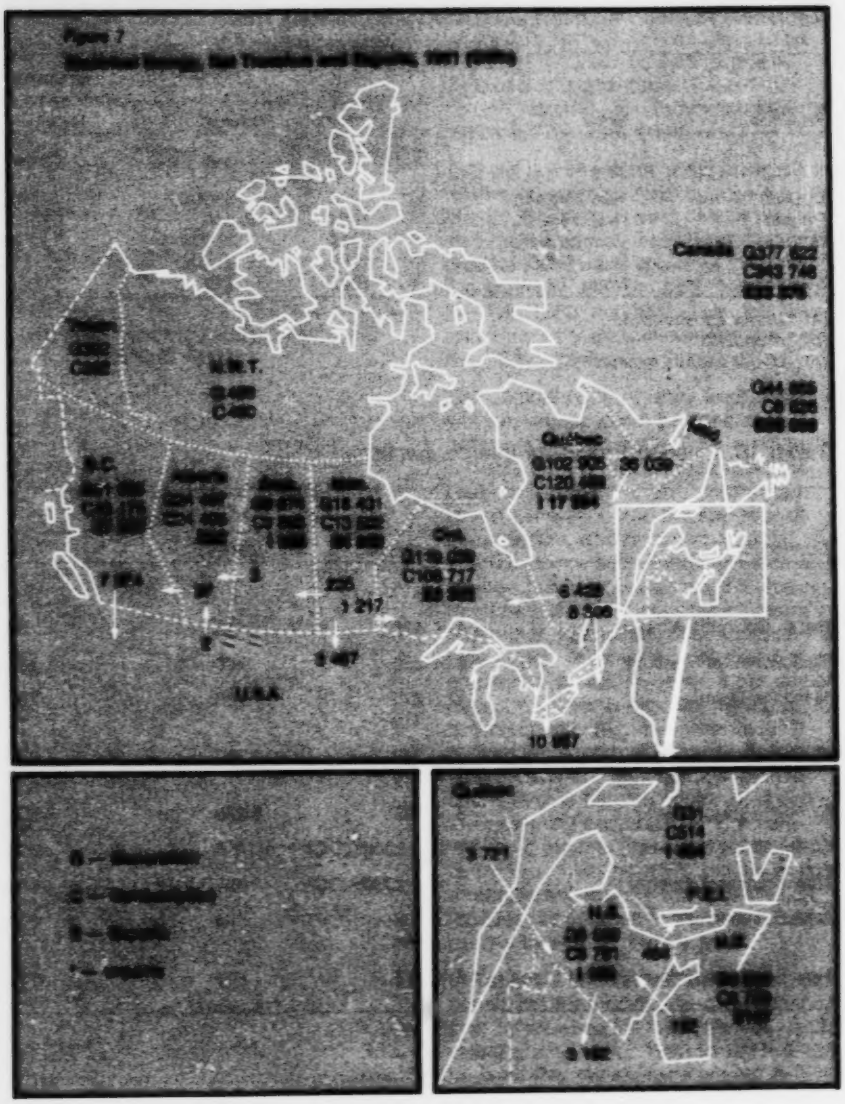


Table 17. Planned Interconnections to the United States

Province	State	Completion date	Voltage	Estimated power transfer capability
			(kV)	(MW)
Quebec [c]	New England	1986	300DC	600
Ontario [b]	New York	1984	2x345	± 150
Ontario [c]	Pennsylvania	1985	300DC	1 000
Manitoba [c]	Nebraska/Dakotas	1988	± 450DC/500 AC	1 000
Saskatchewan [a]	North Dakota	1982	230	200

(a) Under construction
(b) Proposed
(c) Under serious review

Table 18. Existing Provincial Interconnections

Connection	Voltage	Capacity	
		Installed	Firm
	(kV)	(MW)	
British Columbia-Alberta	1 × 138	110	80
Saskatchewan-Manitoba	3 × 230	400	400
Manitoba-Ontario	2 × 230 115	260	260
Québec-Ontario	4 × 230 9 × 120	1 300	1 300
Québec-Newfoundland	3 × 735	5 225	4 300
Québec-New Brunswick	2 × ±230(HVDC)	460	300
New Brunswick-Quebec	2 × ±230(HVDC)	320	160
New Brunswick-Nova Scotia	2 × 138 345	600	600
New Brunswick-Prince Edward Island	2 × 138	200	100

Table 19. Proposed Provincial Interconnections

Province	Connections	Year	Capacity	
			Installed	Firm
	(kV)		(MW)	
British Columbia-Alberta [a]	500(AC)	1984	800	600
Québec-New Brunswick [b]	2 x 230(HVDC)	1986	460	300

(a) Under construction
(b) Under serious review

Electrical energy is supplied by three sources in Canada. Private and public utilities are the primary sources of generation. In addition, a small number of industrial establishments have their own generation facilities. Most industrial establishments generate energy only for their own use, but some sell energy to municipal distribution systems or utilities.

Aggregated, industrial establishments which generate electricity supply about 80% of their total requirements. About 54% of these plants are in the forest products industry, 15% in mining and 11% in metal processing. About 80% of industrial establishments with generation facilities are in Quebec, Ontario and British Columbia, reflecting the concentration of forest product companies, mining companies and aluminum smelting companies in these provinces. Nearly 90% of the electricity generated by industrial establishments is from hydro-electric sources.

As illustrated in Table 20, the amount of energy generated by industry has been a decreasing proportion of the total electrical energy generated in Canada. More detailed information on the amounts of electricity generated by utilities and industrial establishments by province is provided in Table A4.

Greater public ownership of electric utilities has been the trend developing in Canada for some time. Over the years, provincial governments have taken over investor-owned electric utilities, based primarily on such considerations as the resulting lower electricity supply cost, (due largely to such factors as efficiencies created by consolidation of the supply industry, and lower financing cost as a result of the provincial guarantee of debt) and the greater degree of control over electricity supply policy. Some of the provinces use electricity supply and pricing as instruments of socio-economic development policy.

The major electric utilities in each province and territory in Canada, in terms of generating capacity and assets, are provincially-owned except in Prince Edward Island and Alberta. One investor-owned utility supplies electricity in Prince Edward Island. In Alberta, two major investor-owned utilities supply about 80% of the provincial supply while municipally-owned outlets supply most of the remainder. A central planning body, the Electric

CAPITAL INVESTMENT

Utility Planning Council, consisting of representatives from the utilities, is responsible for coordinating generation and transmission facilities for all utilities in Alberta. In addition, greater uniformity of price will result from the new Alberta Electricity Marketing Board. Details of this body are provided in the section: "Developments in 1981". In Newfoundland one investor-owned utility distributes 36% of the electricity used in that province; it purchases about 15% of this electricity, mainly from Newfoundland Hydro. In the Yukon and Northwest Territories, the federally-owned Northern Canada Power Commission generates and distributes most of the electricity supplied. Two privately-owned utilities supply almost all of the remaining electricity. Additional information is provided in the special feature in this issue, "Electricity North of 60°".

Most of the electricity in all provinces is distributed to consumers by the major utilities. The one exception is Ontario, where a very large proportion is purchased from Ontario Hydro and distributed by some 330 municipal utilities. Investor-owned utilities supply a small amount of electricity in this province, some of which they generate themselves. The rest is purchased from Ontario Hydro. The names of the electric utilities in each province can be found in the Statistics Canada publication 57-204, Electric Power Statistics Vol. I.

As indicated in Table 21, a total of 59,955 people were employed by the electric utilities in 1980 in design, construction, administrative and operating capacities. Of this workforce, 91% were employed by public utilities, the remaining 9% by private utilities. The utilities had assets totalling $55 billion in 1980, and revenues of $11 billion.

It is clear from Table 21 that Hydro-Québec and Ontario Hydro are the two largest electric utilities in Canada. In fact, they ranked second and fifth respectively in all of North America in terms of net income in 1980. Together the two utilities account for 65% of total assets and 66% of total revenues for Canadian electric utilities.

Table 20. Production by Utilities and Industrial Establishments, 1970-1981

Year	Utilities	Industrial Establishments
	(%)	
1970	84	16
1975	87	13
1977	88	12
1979	90	10
1981	90	10

SOURCE: Statistics Canada, Publications 57-202, 57-001.

Utility investment for new facilities increased by almost 12% in 1981, to an estimated $7.8 billion. Approximately 60% was for generation, 21% for transmission, 9% for distribution and the remainder for other items.

The amount of electric utility investment relative to energy supply capital investment, total capital investment in the economy, and to Canada's gross national product (GNP), are shown in Table 22 for five year periods from 1966 to 1975, and for 1979, 1980, and 1981. This data illustrates the very capital intensive nature of electricity supply.

The original costs of utility fixed assets in service, broken down by generation, transmission and distribution, are shown in Table 23. For the Canada total, the costs remain fairly evenly divided between generation and the sub-total of transmission, distribution and "other", which includes such things as office and storage buildings. However, this investment pattern varies considerably from one region to another, depending on the type of generation mix employed. For example, the capital investment per unit of capacity added, is significantly higher for hydro capacity than it is when adding conventional thermal capacity. This is because the hydro generation station is characterized by high capital cost and low operating cost, relative to a conventional thermal plant. In addition, the hydro facility will normally require a higher capital expenditure for transmission facilities, since the generation plants are usually located in remote areas.

In Table 24, which illustrates capital expenditures for electrical system expansion by province for 1981, as well as providing estimates for 1982 to 1991, it can be seen that the average annual increase in capital expenditures from 1981 to 1991 is expected to be about 13%. Escalation is expected to be about 8-9% during this period, therefore real growth in capital expenditures is expected to be between 4 and 5%. This data is based on utility estimates received in January 1982. Since that time, both Hydro-Québec and B.C. Hydro have reduced their demand forecasts, which will subsequently reduce their expected capital expenditures during this period. As a result, although Quebec is responsible for the largest portion of these expenditures, almost 61% of the total in 1991, this pro-

portion will probably be reduced when new forecast data is available. The historical data in Table 25 indicates that capital expenditures since 1965 have increased at an average annual rate of 13.7%. The average annual rate of inflation over this period was 5.4%, which indicates that real growth was about 8.3%. There is significant excess generation capacity at present, in some provinces, which will result in lower capital investment over the next five years. This excess capacity is due to reduced growth in electricity demand that was forecast when construction was initiated, some five to ten years ago. As a result, some deferrment of additional capacity is possible.

Table 21. Electric Utility Assets and Revenue, 1980

Utilities by Province	Assets ($000)	Revenues ($000)	Employees
British Columbia	6 627	925	4 672
Alberta	3 168	807	4 408
Saskatchewan	1 117	272	2 004
Manitoba	2 743	420	3 327
Ontario	17 485	4 847	18 646
Quebec	18 128	2 531	20 453
New Brunswick	2 403	487	2 056
Nova Scotia	1 034	358	2 160
Prince Edward Island	61	40	234
Newfoundland	2 034	355	1 680
Yukon and Northwest Territorities	213	74	315
CANADA TOTAL (all utilities)	55 014	11 117	59 955

SOURCE: Statistics Canada, Publication 57-202

Note: The totals may not correspond with the sum of the elements due to rounding.

Table 22. Electric Utility Capital Investment

	1966-70	1971-75	1979	1980	1981
Investment in electric power ($ billions)	6.8	12.9	6.4	6.4	7.8
As percentage of investment in:					
Total Energy	55	56	55	44	43
Total Economy	8	9	12	10	9.8
As percentage of GNP	1.9	2.0	2.8	2.2	2.4

SOURCE: Energy, Mines and Resources data and Statistics Canada Publications 61-205 and 11-003E.

Table 23. Original Cost of Utility Fixed Assets in Service

	1970		1975		1977		1978		1979		1980	
	($000)	(%)	($000)	(%)	($000)	(%)	($000)	(%)	($000)	(%)	($000)	(%)
Generation	6 883	48	10 549	48	14 628	51	16 320	51	19 177	52	22 431	53
Transmission	3 087	22	4 802	22	5 804	20	6 209	20	7 421	20	8 465	20
Distribution	3 228	23	5 007	23	6 302	22	7 168	22	7 950	21	8 739	20
Other	1 043	7	1 712	7	1 968	7	2 278	7	2 601	7	2 927	7
Total	14 241	100	22 070	100	28 702	100	31 975	100	37 149	100	42 562	100

SOURCE: Statistics Canada, Publication 57-202

Table 24. Forecast of Electric Utilities Capital Expenditures

Province	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
	(Millions of Current Dollars)										
Newfoundland	156	208	217	120	129	172	183	204	231	262	268
Prince Edward Island	12	14	6	4	7	7	7	7	7	7	8
Nova Scotia	49	96	191	202	190	219	231	88	164	198	203
New Brunswick	286	161	61	42	44	48	56	54	50	50	40
Québec	2 793	3 219	3 589	3 408	3 597	5 186	6 534	8 729	12 095	14 864	16 567
Ontario	2 460	3 032	3 245	2 647	3 219	3 252	3 704	3 490	3 606	3 342	3 579
Manitoba	107	132	140	117	90	85	106	244	366	399	422
Saskatchewan	226	263	340	400	394	440	480	670	970	550	560
Alberta	585	829	1 020	1 209	1 073	1 043	1 177	1 446	1 574	1 725	1 577
British Columbia	1 084	1 385	1 408	1 427	2 042	2 948	3 594	3 775	3 990	4 049	4 110
Yukon and Northwest Territories	7	8	18	6	17	28	11	17	13	13	14
CANADA	7 765	9 347	10 235	9 582	10 802	13 428	16 083	18 724	23 066	25 459	27 348

SOURCE: Department of Energy, Mines and Resources based on Utility Estimates.
Fiscal and calendar years combined.

FINANCING

From 1960 to 1976, debt was increasingly used to finance utility expansion. In 1976, debt accounted for 88% of capitalization in those provinces which have predominantly publicly owned utilities, while it was 51% for those provinces which have predominantly investor-owned utilities. By 1980, debt for publicly owned utilities decreased slightly to 87% while it was 48% for investor-owned utilities. The higher degree of business risk faced by the investor-owned utilities which provide most of the electricity in PEI and Alberta, requires that their debt be a lower percentage of the total. The debt of the publicly owned utilities is guaranteed by the provinces in which the utilities are located. Table 26 indicates that the debt proportion has been declining slightly since 1976, as utilities are using internally generated funds for a greater percentage of new capital requirements. Studies indicate that a debt of approximately 80% of the capital structure is appropriate for publicly- owned utilities, so the reduced debt portion is a prudent move. In this period of heavy capital requirements for system expansion, plus uncertainty and high interest rates in the money markets, it is prudent for utilities to be financially sound.

The debt of the Federal Crown Corporation, the Northern Canada Power Commission, which supplies most of the electricity in the Yukon and Northwest Territories, is provided by the federal government.

The utilities used internally generated funds (net income plus non-cash charges to income) for about 30% of the capital expenditures during 1980, about the same as for the period of 1965-75. It is expected that over the next five years, internally generated funds will meet about 30-35% of capital requirements.

Table 25. Historical Electric Utility Investment

Year	Generation	Construction			Machinery and Equipment	Total
		Transmission and Distribution *	Other	Sub-Total		
		(millions of current dollars)				
1965	438	277	12	727	212	939
1966	493	281	13	787	356	1 413
1967	577	262	36	875	390	1 265
1968	533	301	54	889	443	1 332
1969	511	281	63	856	546	1 403
1970	581	449	28	1 057	554	1 610
1971	572	472	36	1 079	668	1 747
1972	636	449	50	1 135	619	1 754
1973	808	539	69	1 417	827	2 244
1974	1 049	598	53	1 700	1 054	2 753
1975	1 691	874	96	2 661	1 296	3 957
1976	1 803	821	30	2 654	1 574	4 229
1977	2 205	911	43	3 158	1 726	4 884
1978	2 339	1 199	233	3 761	2 175	5 936
1979	2 516	1 424	181	4 121	2 243	6 364
1980	2 291	1 434	296	4 021	2 426	6 447
1981(a)				4 481	2 715	7 196

* *Transmission and Distribution includes street lighting. Generation includes transformer stations, dams and reservoirs.*

(a) Intentions, breakdown not available.

SOURCE: Statistics Canada Publications 57-202, 61-205, and 61-206. Canada Year Book 1968-79.

Table 26. Electrical Utility Financial Structure

Province	1970		1975		1976		1977		1978		1979		1980	
	(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)
							(%)							
Newfoundland	82	18	81	19	79	21	76	24	73	27	74	26	72	28
Prince Edward Island	45	55	58	42	53	47	54	46	50	50	51	49	51	49
Nova Scotia	77	23	101	–1	103	–3	102	–2	99	1	98	2	95	5
New Brunswick	88	12	91	9	92	8	92	8	94	6	93	7	91	9
Québec	74	26	75	25	76	24	76	24	77	23	76	24	75	25
Ontario	66	34	74	26	77	23	77	23	79	21	79	21	78	22
Manitoba	93	7	96	4	97	3	97	3	95	5	93	7	93	7
Saskatchewan	81	19	70	30	73	27	77	23	78	22	78	22	79	21
Alberta	56	44	53	47	49	51	47	53	47	53	46	54	44	56
British Columbia	94	6	94	6	94	6	95	5	87	13	86	14	86	14
Yukon and Northwest Territories	77	23	99	1	98	2	99	1	98	2	98	2	97	3
CANADA	75	25	79	21	83	17	80	20	80	20	79	21	78	22

(a) Debt: Long-term + short-term.
(b) Equity: Total of reserves and capital surplus.
SOURCE: Statistics Canada, Publication 57-202.

Table 27. Average Revenue From Electricity Sales by Province

Province	1968	1970	1972	1974	1975	1976	1977	1978	1979	1980
					(CURRENT CENTS /kWh)					
Newfoundland	0.9	1.0	1.1	1.3	1.4	1.4	1.7	2.0	2.2	2.3
Prince Edward Island	2.9	2.8	3.0	3.7	4.1	5.1	5.9	6.4	7.2	8.1
Nova Scotia	1.9	1.9	1.8	2.0	2.5	2.8	3.9	4.4	4.6	4.5
New Brunswick	1.5	1.6	1.5	1.6	1.9	2.0	2.4	3.2	3.7	4.1
Québec	0.9	1.0	1.0	1.1	1.3	1.4	1.5	1.7	2.0	2.2
Ontario	1.0	1.1	1.2	1.4	1.6	1.8	2.3	2.4	2.6	2.9
Manitoba	1.1	1.1	1.0	1.2	1.4	1.7	1.9	2.3	2.7	2.8
Saskatchewan	1.9	1.7	1.6	1.6	1.8	2.1	2.4	2.7	2.7	2.9
Alberta	1.6	1.5	1.5	1.7	2.0	2.4	2.7	3.1	3.2	3.4
British Columbia	1.2	1.3	1.3	1.4	1.6	1.8	2.1	2.2	2.4	2.6
Yukon	–	2.2	2.4	2.6	2.7	3.5	4.1	4.4	4.9	5.3
Northwest Territories	–	2.5	3.2	3.6	4.0	5.2	6.9	7.7	9.0	10.0
CANADA	1.1	1.1	1.2	1.3	1.5	1.7	2.0	2.3	2.5	2.8

SOURCE: Statistics Canada, Publication 57-202.

COSTING AND PRICING

Costing

The unit cost of supplying additional electricity increased rapidly during the 70's. However, in recent years cost increases have been about equivalent to the rate of inflation, resulting in little increase in the real cost of electricity. It is expected that most of the large electricity cost increases are now behind us and there will be few real cost increases during the 1980's in most parts of Canada.

The two basic reasons for the rapid increase in the cost of new facilities in the 70's were the significant increase in the rate of inflation, and the dramatic increase in the cost of fossil fuels.

High levels of inflation affect the electric utility industry in two ways: by increasing the capital cost of constructing additional facilities and by increasing the interest rate that must be paid for borrowed funds, a major consideration for such a capital intensive industry. The average interest on long-term utility debt is shown in Figure 8, for the period 1966 to 1981. The index of electric utility construction costs is shown in Figure 9. This figure illustrates the very significant increase in utility construction costs between 1973 and the present, a trend shared by most capital projects. Construction costs parallel the CPI index prior to 1973 and from 1977 to the present. However, they increased very rapidly, even relative to the rate of inflation, as measured by the CPI, during the period 1973 to 1977.

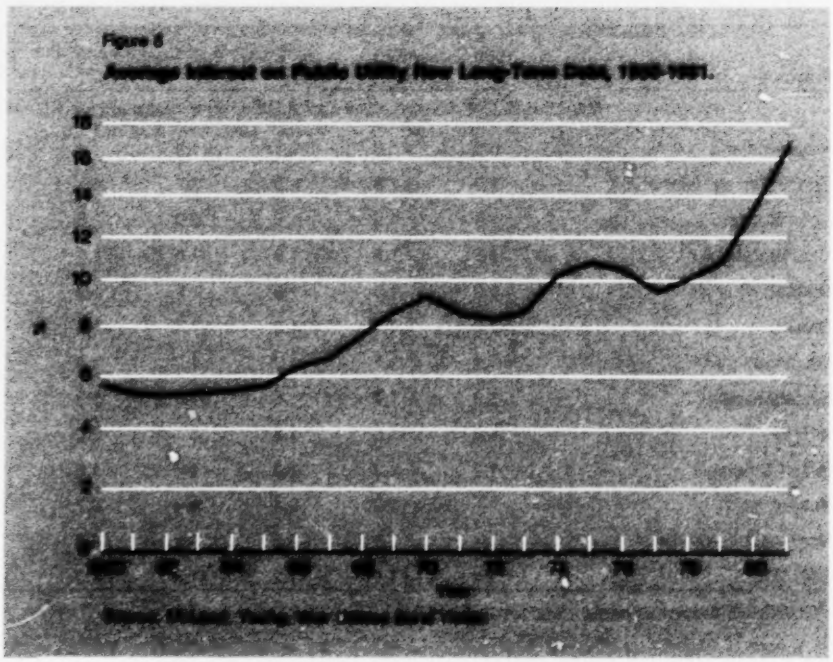
Figure 10 indicates the sharp increases in fossil fuel costs, which the utilities have experienced during 1973 and 1974. For Canada in total, the fuel cost per kWh generated from fossil fuels has increased five-fold between 1973 and 1980, but oil costs moderated somewhat in 1981. The impact of this cost increase varies considerably from one region of the country to another, depending on the type of fuel used, its source and the percentage of total energy supply derived from fossil fuel plants. Earlier sections of this publication provide regional breakdowns for fuel use and generation mix.

Pricing

Data on the average revenue from electricity sales for each province is provided in Table 27. The unit revenue for Canada was quite stable up to about 1972, when the cost began to escalate for reasons outlined in the section on Costing. These costs increased more rapidly in some regions than others, depending on differences in generation mix, fuels used, and the rates of system expansion, to meet the increased demands for electricity. Table 28 gives monthly electricity costs for selected Canadian cities, and Table 29 details the average annual rate increases for all customers, by major utilities in each province since 1974.

Figure 11 which illustrates the movements of the electricity and oil/gas components of the Consumer Price Index, as well as the movement of the Consumer Price Index total, indicates that the electricity price component has increased more slowly than, or equal to, the rate of increase of the CPI for most of the period since 1955. The sole exception is the period from 1974 to 1977, when the electricity price component increased at a much faster rate than the CPI rate of increase. However, the electricity price component is seen to be increasing at a slower rate than the energy price component.

Ontario Hydro has developed a set of proposed rate changes which incorporate most of the Ontario Energy Board (OEB) suggestions from the December 1979 report on the utility's costing and pricing methods. It was recommended that time differentiated rates based on accounting costs be introduced initially to large customers. It had been intended to have proposed rate changes heard by the OEB in 1981 for introduction in 1982. However, Ontario Hydro decided that the



affected customers have not had adequate time to assess the proposed changes and comment on them. Their reactions will be heard until 1982, and not introduced until 1983 at the earliest.

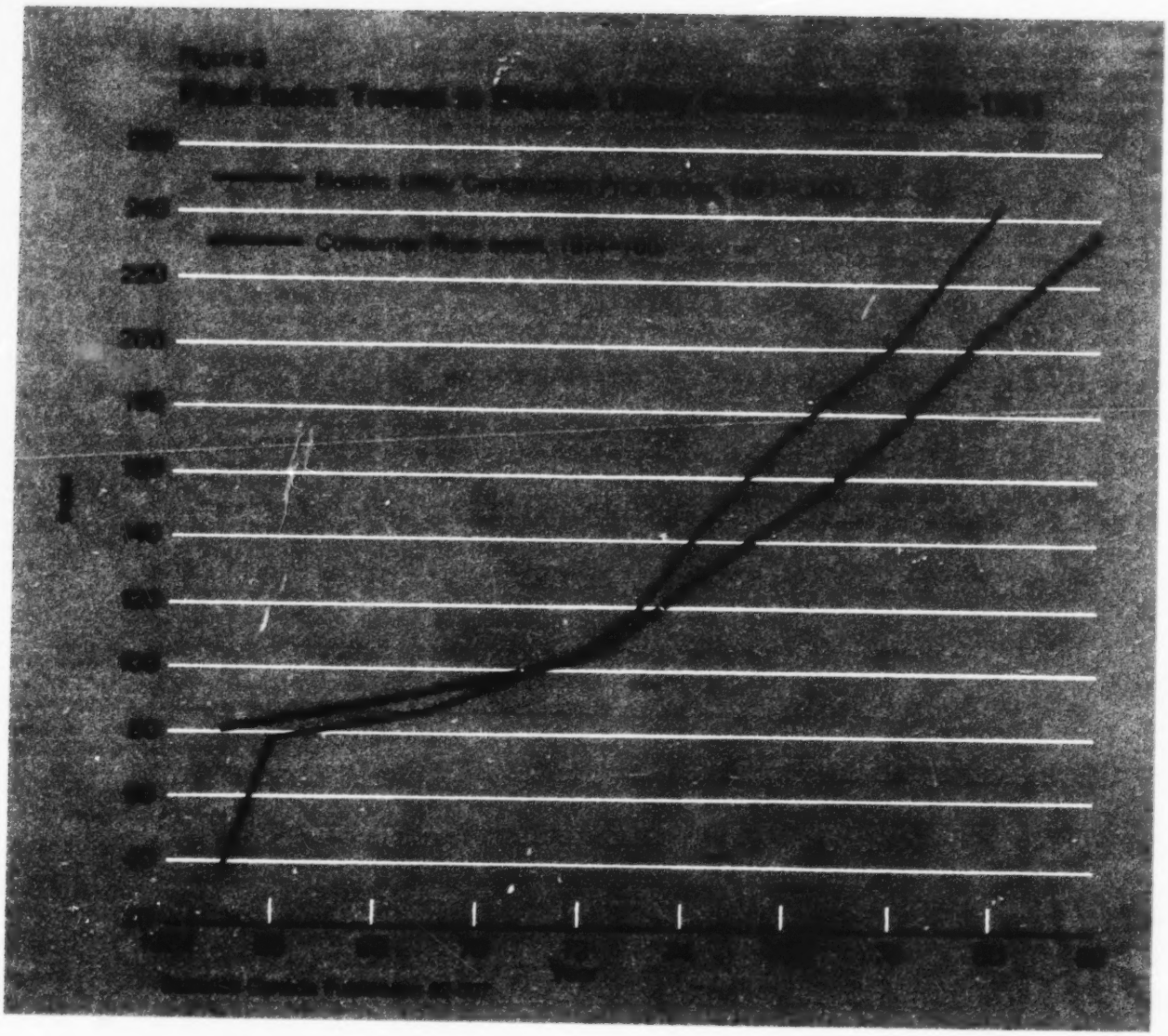
Hydro Quebec has altered its domestic rate structure from a declining block rate to an inverted block rate structure, where the cost per kilowatt hour increases with the amount consumed. Hydro Quebec is the only Canadian utility to implement this type of rate structure.

There has been little public discussion of rate structure changes, such as time differentiated rates, in other provinces. However, several utilities indicate that they are moving away from the declining block rate, toward a rate structure consisting of a fixed service charge, plus a single rate for energy. They are also reducing the number of rates and in general, simplifying the rates.

Table 28. Monthly Electricity Costs for Selected Canadian Cities, January 1981

Sector	Residential	Commercial	Industrial
Billing demand (kW)	–	100	1 000
Consumption (kWh)	1 000	25 000	400 000
		($)	
Vancouver	36.63	915.13	10 587.57
Calgary	33.74	1 077.54	11 668.19
Edmonton	33.60	991.90	12 526.88
Regina	31.67	935.60	11 288.40
Winnipeg	30.86	815.31	9 765.31
Toronto	35.70	1 138.05	13 554.00
Ottawa	32.60	849.58	11 994.58
Montreal	30.40	1 023.50	11 719.00
Moncton	48.62	1 576.50	15 350.00
Halifax	49.15	1 587.75	16 411.06
Charlottetown	78.78	2 387.70	28 040.35
St. John's	42.80	1 188.83	13 496.08
Whitehorse	48.48	1 632.10	n/a
Yellowknife	55.87	1 808.00	n/a

n/a: not applicable
SOURCE: Statistics Canada, Publication 57-203



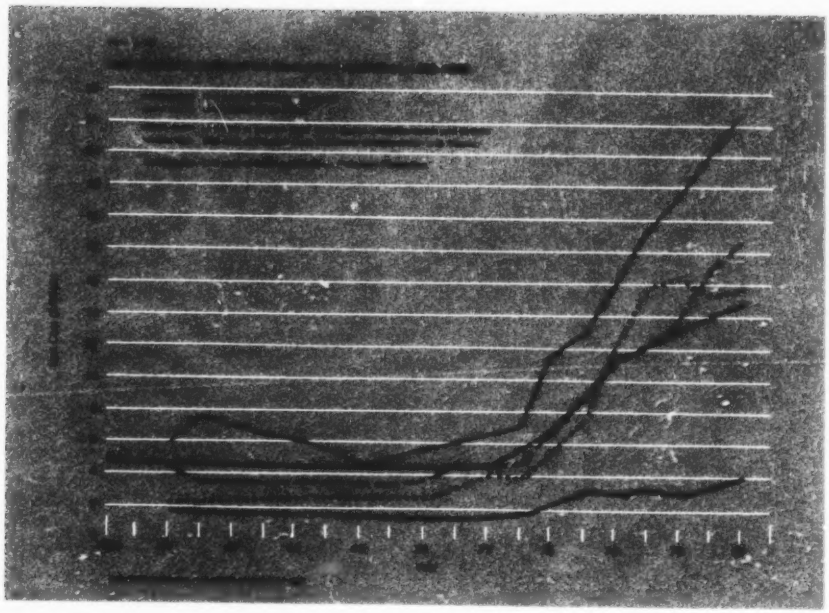
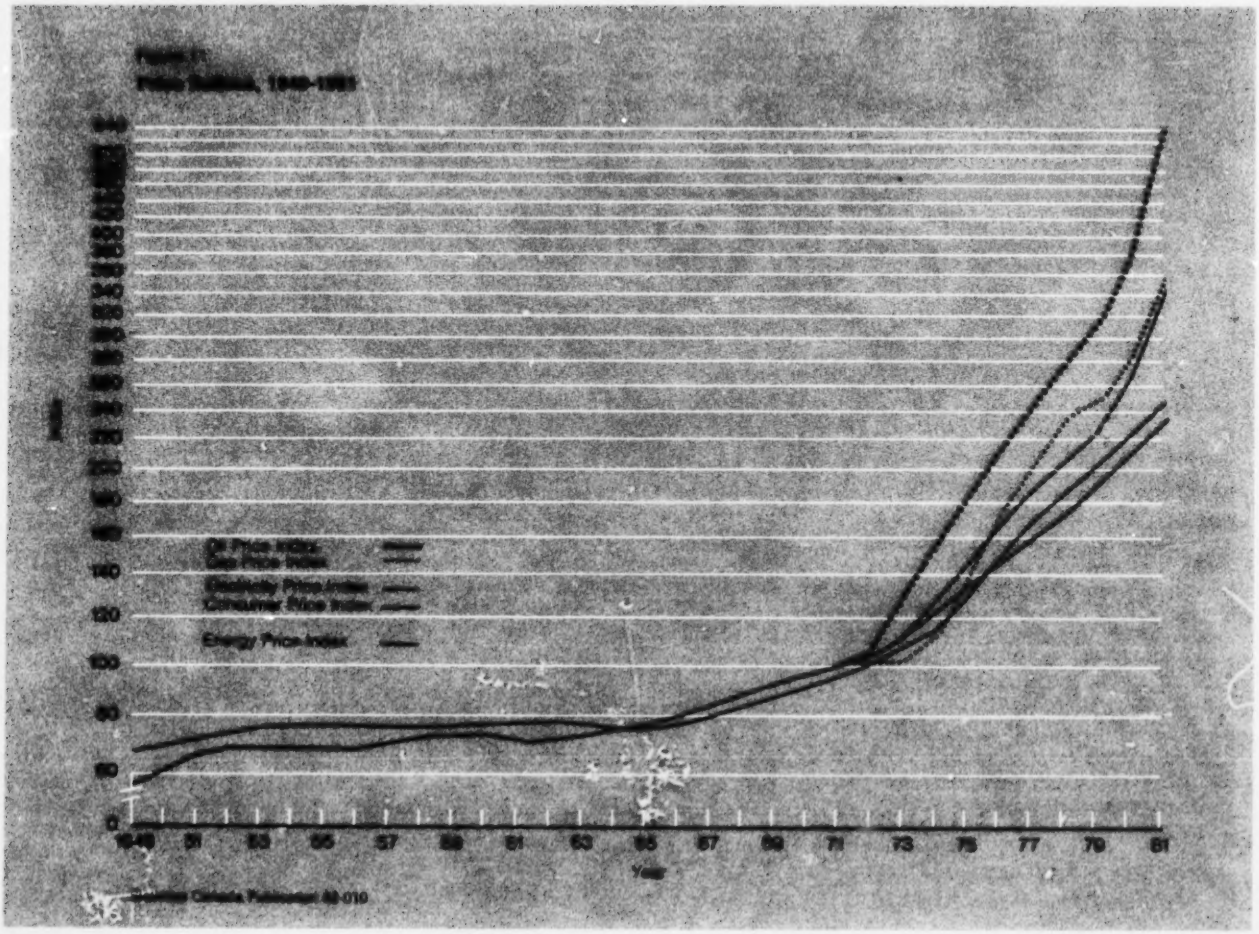


Table 29. Average Annual Rate Increases, 1974-1981

UTILITY	RATE CHANGES (%): AVERAGE OF ALL CUSTOMER CLASSES							
	1974	1975	1976	1977	1978	1979	1980	1981
B.C. Hydro	15.0	6.2	14.2	12.1	13.4	5.5	7.6	10.0
Alberta Power	19.0	21.3	11.4	20.2	-	-	12.3	28.9
Trans Alta. Utilities	5.2	17.6	25.8	14.7	15.6	7.5	-	13.0
Edmonton Power	-	13.6	10.1	6.0	8.1	-	26.0	12.0
Saskatchewan Power	-	27.0	13.0	17.0	3.3	8.3	7.9	16.1
Manitoba Hydro	18.1	17.4	16.6	15.0	14.9	14.4	–[1]	-
Ontario Hydro	9.9	11.4	14.9	25.6	5.7	7.7	7.3	10.0
Hydro-Québec	-	9.8	10.3	9.9	18.7	13.7	13.3	10.6
N.B. Power	-	10.0	12.0	16.6	9.9	7.9	7.8	9.8
N.S. Power	-	4.6	-	43.0	14.0	12.5	–[2]	-
Maritime Electric	10.0	20.0	–8.0	17.0	13.0	-	13.1	21.4
Nfld. Light & Power	6.4	33.5	13.4	9.8	21.2	12.4	11.8	14.6
Nfld. Hydro	–[3]	–[3]	14.0	8.4	25.0	-	19.0	15.8

NOTES

(1) The provincial government froze the rates in 1979 until 1984.
(2) The provincial government froze the rates in 1980.
(3) Information available only from 1976.


Oil Price Index
Gas Price Index
Electricity Price Index
Consumer Price Index
Energy Price Index
1948
51
53
55
57
59
61
63
65
67
69
71
73
75
77
79
81
Year

ALTERNATE ENERGY SOURCES

This section provides an update on the status of developments in Canada for alternative energy sources – geothermal, wave energy, river current energy and tidal energy, as well as small scale hydro and photovoltaics.

Geothermal Energy

Federal government geothermal energy research and development funding began in 1976. Originally, the prime objective of the program was to identify and assess exploitable geothermal resources in Canada. With increasing knowledge of the resource, the research is shifting towards extraction technology, although the resource work will continue. The program has identified probable geothermal resources for electricity production at Meager Creek in British Columbia.

The Meager Creek resource is in the final stages of assessment. A deep well drilling program is continuing into 1982. Following assessment of the results, a decision will be taken as to whether or not a demonstration generating plant will be built; it is unlikely that construction of such a plant would begin before 1984. If a plant is built, it is likely to be about 50 megawatts, completed in about five years and at a cost of about $100 million. The potential for the Meager Creek site has been estimated in the range of 500-1000 megawatts of electricity generation.

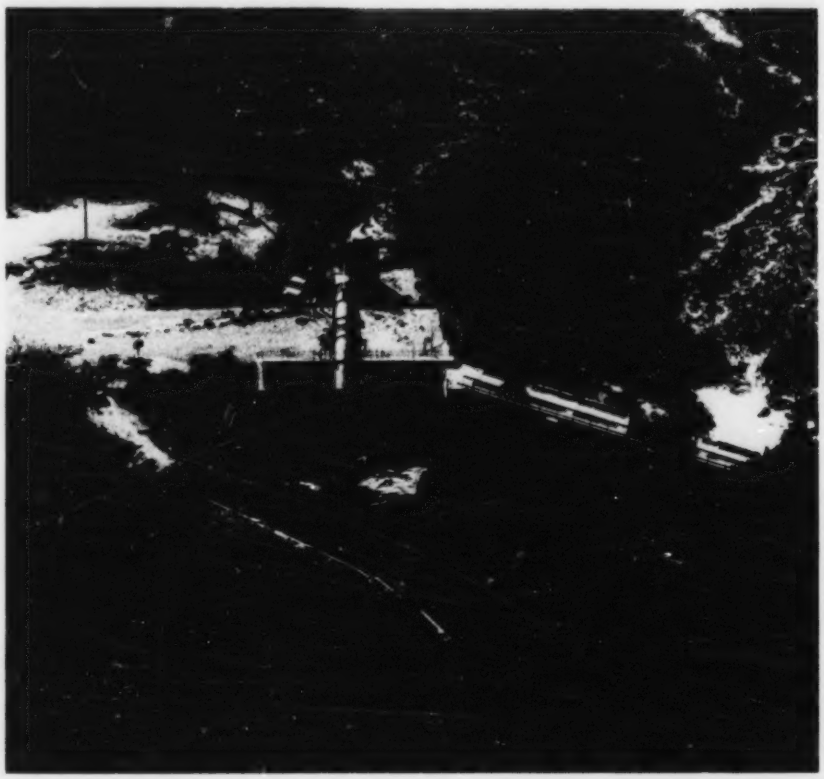
Wave Energy

The extraction of energy from waves must be considered to be a long range endeavour and an uncertain competitor with other energy sources available in Canada. Current estimates of wave energy costs are 10-20 times that of energy from conventional sources. Several studies have been conducted on Canadian wave energy potential and Canada has participated in a wave experiment with the International Energy Agency. As a result, it has been recommended that further work on wave energy devices be reduced and only a state of the art awareness of this technology be maintained. A similar conclusion has been reached by Britain, which has substantially reduced its funding for the wave energy assessment program.

Energy from River Currents

A study has identified those stretches (or reaches) of Canada's fourteen largest rivers and tidal estuaries in which currents exceed 1.5 mps (meters per second), width exceeds 50 meters and depth exceeds 3 meters; criteria from which a large electricity generation potential exists. For example, if three of the largest Canadian rivers – the Fraser, the Mackenzie and the Slave – were tapped by large vertical axis water mills (VAW), it is estimated that they could produce 6 000 MW at 35% efficiency from the potential of the current. However, extraction of current energy requires very large machines.

For open river and tidal currents, Canada is actively pursuing the VAW technology. The design is very similar to the vertical axis wind turbine except that the VAW has straight hydrofoil blades mounted on the vertical axis. The test results were very encouraging (40% efficiency). Other tests on this design are being conducted, including flow acceleration by means of ducting. A contract has been set by the federal government that will result in the manufacture of three VAWs of about 2 meter diameter, each with about a 5 kW output. One of these units probably will be tested in the St. Lawrence River, another in a Nova Scotia tidal setting and a third used for cross-country demonstration purposes. If these prove successful, the next stage might be a 15-20 foot diameter unit.



Ontario Hydro's Wasdell Falls Mini-Hydel generating station, placed in service in 1981. A similar unit has been placed in service by Ontario Hydro at Sultan.

Wind Energy

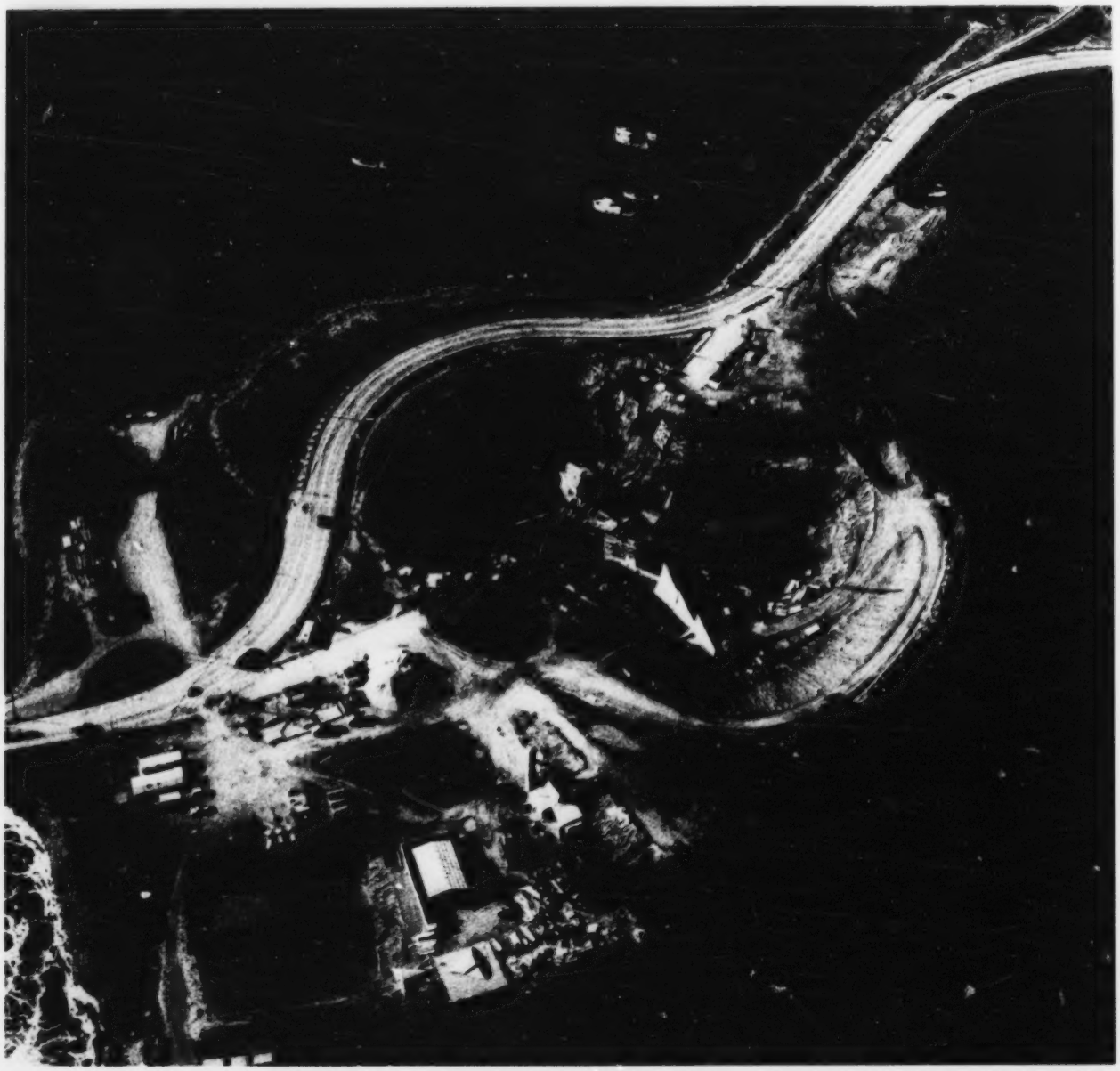
The major objectives of the Canadian wind energy program remain:

(a) to determine under what circumstances wind energy can make a viable contribution to Canadian energy supplies.

(b) establish the technology of wind energy conversion systems (WECS) appropriate to Canadian conditions.

(c) encourage and support Canadian industrial initiatives in the design and manufacture of WECS for both domestic and export markets.

The Canadian research and development effort has concentrated exclusively on the vertical axis wind turbine, since it is considered to be the most cost-effective design for generating electricity. Information is now being collected on the performance of relatively small vertical axis wind



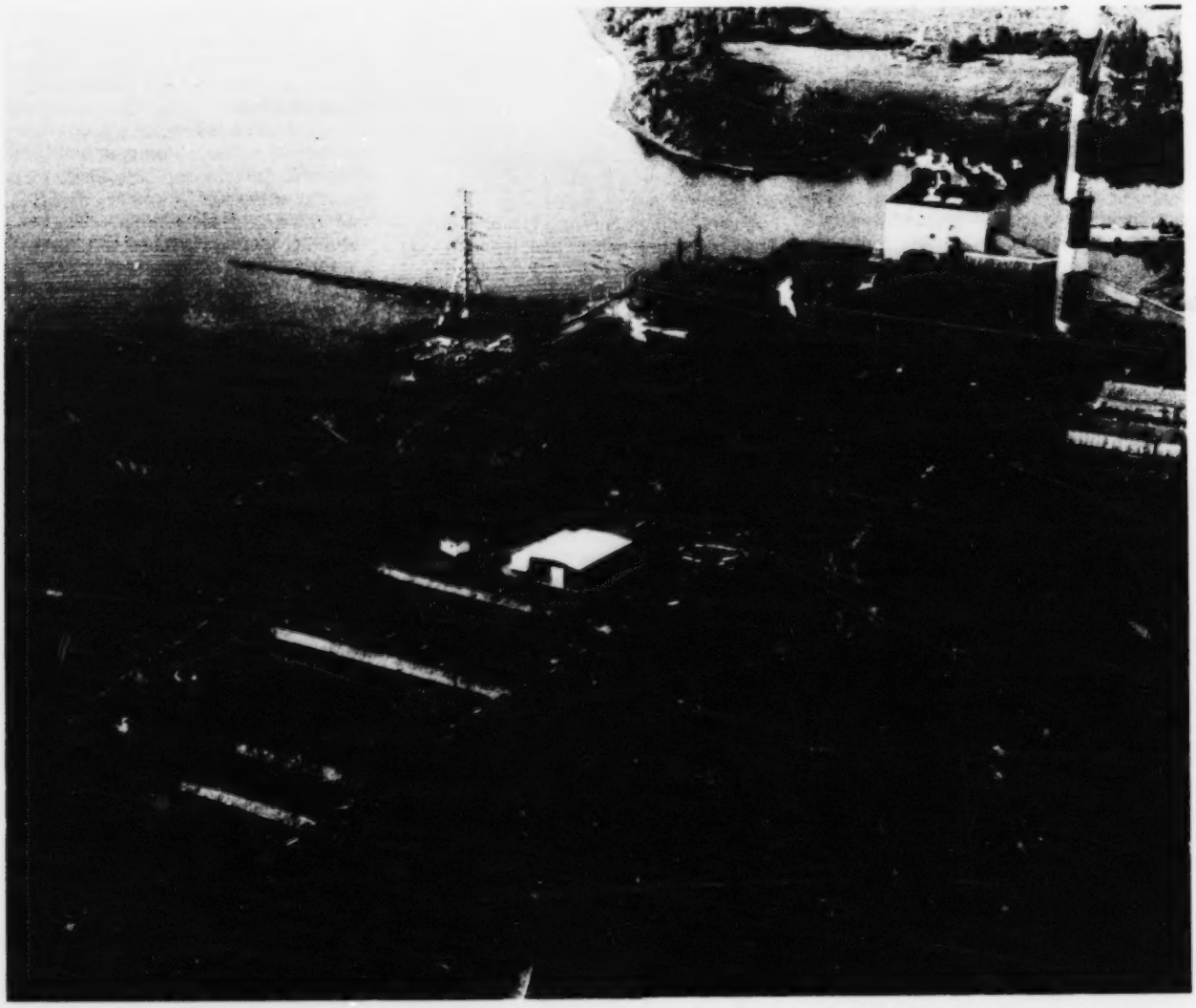
Aerial view of construction of Nova Scotia Power's Annapolis hydro demonstration plant, being installed in the existing causeway across the tidal river. The project is designed to demonstrate a new concept for low-head and tidal applications. The low-head 17 MW straight-flow turbine will be in service in 1983.

turbines. Manufacturing technologies have been established for machines up to 250 kW. Cost projections indicate that they are economically viable for some applications, but there are technical considerations that require further investigation, including a greater understanding of structural reliability. Research is being carried out on aerodynamic performance, load calculations, airfoil characteristics, structural dynamic analyses and systems analyses. Field trials are underway to provide physical verification of the analytic techniques, including 10 and 100 kW wind/diesel hybrids, and 50 and 230 kW grid-coupled units.

Hydro-Québec and the National Research Council are cooperating on project AEOLUS (the Greek god of the winds), which will result in the world's largest vertical axis windmill, to be completed by about 1986. The preliminary specifications for the AEOLUS estimate its height at approximately 110 meters, with a swept area of 4000 square meters. The cost will be in excess of $30 million. This will be the first megawatt-scale vertical axis wind turbine and it is hoped it will be the forerunner of a number of such grid-coupled supplements to the power base of utilities.

Tidal Energy

The economic and financial feasibility studies of Fundy tidal power, which were



The four small ponds in the left foreground are used to raise fish, using the warm discharge water from New Brunswick Power's Grand Lake coal-fired generating station.

completed in 1977, were updated in 1981. Preliminary results from those studies indicate that the larger B-9 site (4500 MW), across the Cobequid Bay would be economically and financially feasible, if about 90% of the power were exported to the United States. After review by the federal-provincial governments, a decision will be made as to what further steps will be taken towards the goal of developing a full scale tidal power project in the Bay of Fundy.

Small Scale Hydro

Several provinces are continuing to assess small scale hydro potential and a number of demonstration projects are being developed. Emphasis has been given to the potential replacement of diesel generation in remote communities.

Analysis at this time indicates that the expansion of existing small hydro stations or the retrofit of decommissioned hydro units within power grids is economically and financially viable. However, the development of new small hydro sites will involve greater capital costs, which is seen as a major restraint for developers, due to the longer pay-back period.

Under the Federal Conservation and Renewable Energy Development and Demonstration Agreements (CREDA), the federal government supports five small- scale hydro projects in British Columbia, one in the Yukon, three in Nova Scotia and one in Prince Edward Island. In addition, the Remote Community Demonstration Program (RCDP), announced by the Minister of Energy, Mines and Resources in April 1982, allocates $24 million in federal funds to reduce oil consumption for electric generation and space heating in areas not connected to an electrical grid or natural gas system. Small scale hydro development is expected to contribute significantly to the program.

The Ontario Government has instigated an extensive study to identify an inventory of suitable small hydro sites. The inventory will include crown land sites, canal dams and private dams. The Government is also supporting three micro-hydro systems: the 80 kW Galt Energy System at Guelph Dam, the 18 kW Leroy-Somer Canada Limited installation at the Dovion Fish Hatchery sub-station north of Thunder Bay, and the 30 kW system of Barber Hydraulic Turbine Limited north of Toronto. Ontario's Energy Minister also announced approval for private development of small hydro sites which produce an average energy capacity of less than 2 MW. This permits all prospective developers to apply for the right to develp Crown-held small and micro-hydro projects on an equal basis. Its publication "Micro-Hydro Power" serves as a guide for private developers working on installations of 100 kW or less.

The Federal Department of Public Works has recently announced a call for proposals for the leasing, rehabilitation and operation of the Rideau Falls generation station in Ottawa. The project will serve as an example to encourage private developers of small hydro projects on crown land.

The Federal Department of Energy, Mines and Resources, in cooperation with Environment Canada, organized and participated in a conference on Environmental Compatible Hydro Development. The conference, which took place in May 198l, was sponsored by the Ontario Region of the Canadian Water Resources Association. The conference focused national attention on the environmental benefits of hydro-electic power development, particularly the small-scale and low-head plants.

Photovoltaics

Photovoltaics refers to the technology of direct conversion of sunlight to electricity. This solid-state technology is in the general area for which Canada has established an industrial base over the last few decades. To date, the generation of electricity by photovoltaic devices has been limited to low power needs (remote microwave repeater stations) or exotic installations (earth satellite power supplies). Research is now underway to examine reducing costs and increasing reliability to the point where photovoltaics can make a small but significant contribution to Canada's electrical supply. This is a long-term electrical option but the underpinnings of the technical capability must begin now.

Structure of Research and Development in Canada

The administration and execution of electrical research in Canada is carried out by governments, industry, associations, consultants and academic institutions. Research and development must encompass not only electrical topics in a narrow sense but a broad range of civil and mechanical engineering disciplines, social and economic topics and environmental questions, all of which contribute to the production, distribution and use of this energy form.

At the federal level, the Department of Energy, Mines and Resources (EMR), the National Research Council (NRC), the Natural Sciences and Engineering Research Council (NSERC) and Atomic Energy of Canada Limited (AECL) have administrative and, in the cases of NRC and AECL, functional responsibility for electrical research. Co-ordination of federal energy R&D is provided by the Interdepartmental Panel on Energy R&D. It is responsible for making recommendations to Ministers on present and future energy R&D programs. Its mandate includes monitoring of all federal energy R&D activities in the context of the whole national effort and of international activities. EMR provides the chairman and secretariat to the panel. In addition EMR provides funding in the form of grants to the Canadian Electrical Association (CEA) and, under the Research Agreement Program, to academic institutions. In addition to in-house research, the NRC contracts to industry. The NSERC provides funding to academic institutions under regular operating grants, strategic grants and PRAI (project research applicable in industry) grants.

Four of the public utilities (Ontario Hydro, Hydro Québec, Saskatchewan Power and B.C. Hydro) maintain in-house research programs which undertake a variety of activities linked with the design and operating characteristics of the electric utility business. In addition, Manitoba Hydro participates in the research activities of the newly established Manitoba HVDC Research Centre, as well as contributing to the funding of this organization.

Notwithstanding the research programs mentioned above, the structure of electrical research in Canada is enhanced by CEA's research program. While the CEA

program is modest in size when compared to the major investments made by the federal government and the direct investments by the utilities having research facilities, it provides a basis for co-ordinating the research efforts of all utilities with a view to minimizing duplication and filling gaps. The CEA program is a co-operative venture funded jointly by the federal government and virtually all Canadian electric utilities. As a result of the participatory aspect of the program, there is an opportunity for all utilities and government departments represented on the advisory committees to participate in the design of the program. They are encouraged to identify research topics and manage the performance of studies which have been selected through a subcommittee structure. The studies are contracted out to industry and academic institutions and the utilities having research facilities. Apart from administering its research program, one of the priorities of the CEA is continuing liaison with international research organizations to further optimize program selection for Canadian utilities.

Overview of Research Programs

Federal Government

The Atomic Energy of Canada's (AECL) research program for nuclear power development includes activities aimed at improving the reliability and safety of nuclear stations. Expenditures for 1981/82 on nuclear research and utilization are expected to be $111.5 million, an increase of 13% from 1980/81. A total of $17.5 million of this grand total is dedicated to R&D on the immobilization and disposal of radioactive waste. The research mandate is the development and application of nuclear power for peaceful purposes. There are six major categories of research. They are: power reactor systems; advanced fuel cycles; environmental protection and radioactive waste management; heavy water processes; underlying and advanced systems research; and new applications. Heavy water development continues to attract attention with the objectives of improving the performance of existing designs and considering alternative methods of producing heavy water.

The program is also directed to work on developing fuels, including thorium, and to reprocess irradiated fuels for future CANDU reactors with advanced fuel cycles. This would secure fuel supply for long-term operation. The possible applications of the Hydrogen-Water Exchange processes in heavy-water upgrading and tritrium removal are also being investigated.

Considerable progress has been achieved in the research and development program to establish the technologies needed for the permanent disposal of nuclear fuel wastes. Emphasis has been given to the possible disposal of this waste in stable geological formations found in the Canadian shield. These formations are called plutons. Various types of plutons are being investigated in areas of Ontario.

A large-scale Underground Research Laboratory is planned near the Whiteshell Nuclear Research Establishment. The laboratory would be constructed at a depth of about 300 metres and would be the first test facility to be built below the water table in an undisturbed rock formation. Another important area of work involves continuing studies on material performance under intense radiation.

In support of the federal government's off-oil program, AECL is conducting investigations into new applications for nuclear energy, including its application for tar-sands extraction, production of hydrogen by electrolysis, and the use of small (mini) reactors for space heating purposes. Other notable areas of research are aimed at greater understanding at the scientific levels. Subjects such as the physics of radioactive matter and the chemistry of fuel development and waste management are being examined. Developments in these areas will support future advancement of nuclear energy technology.

The non-nuclear areas of the federal energy research program have particular relevance to electrical energy. The main objectives stem from the 1980 National Energy Program and include R&D into substitution, alternate energy sources and efficient energy utilization. Emphasis has been placed on improved coal-firing and fluidized bed combustion, cogeneration, electrical transmission, the application of wind energy to the electric grid and development of water turbines to generate electricity from waves, currents and tides.

The National Energy Program allocated $260 million for the period 1980 to 1983 to expand the core research and development program. An additional $4 million has been designated to support coal R&D in the Atlantic provinces; and $50 million to carry the technical risks involved in the use of new coal technologies, such as fluidized bed combustion. Two alternative energy sources have received particular attention. The sum of $18.7 million in federal funds has been allocated to the construction of an experimental fusion device, Tokamak, at Varennes, Quebec. In addition, the Aeolus wind demonstration project will receive $30 million in funds from NRC and Hydro Quebec. It will be capable of generating 3.8 MW and will supply power directly into the Hydro-Quebec grid. Electrical energy "storage" systems, electric space heating thermal storage, heat pumps and studies regarding expanded coal use in electricity generation are some of the other areas being investigated.

Hydro-Québec

The research program conducted by Hydro Quebec's Research Institute (IREQ) has four major areas of activity: electricity generation and conservation; transmission and distribution systems; system analysis and automation; and materials research. Estimated expenditures for 1981 total $45.4 million, $36 million in operating costs and $9.4 million towards capital costs. Expenditures over IREQ's first five-year plan, ending in 1985, are expected to be $370.8 million.

IREQ has expanded its research activity concerning new sources of electricity, including programs for biomass, solar energy, fusion and electrochemical storage. Research on biomass emphasizes development of gasification technology. Peat, wood and wood waste are being investigated as energy inputs. Solar energy research is in its preliminary stages with the construction of a solar collector test bench which will be used to evaluate air or liquid-cooled collectors and for other R&D purposes. Research on heat pumps have emphasized the use of ground water as the heat source. In addition, assessment of commercial water/air heat pumps and air/air heat pumps is being carried out. In conjunction with the Federal Government, IREQ is involved in two projects mentioned above, the magnetic fusion (Tokamak) facility in Var-

ennes and the Aeolus wind demonstration project. A program for electrochemical storage will explore the use of hydrogen as a link between wind turbines with reconversion through gas turbines and fuel cells. In addition, preliminary studies have been undertaken on methanol production and on high temperature storage.

Research in transmission and distribution systems is aimed at reducing the cost of electrical transmission, improving transmission line reliability and minimizing environmental effects. Specific research over the next five years includes the development of compact transmission lines and multiterminal lines. Information will also be obtained on the dimensions of transmission lines in the l500 kV to 2000 kV range for alternating current and 600 kV to l200 kV direct current.

The Hydro-Québec research program is also aimed at optimizing system planning and development by improving analytical techniques and increasing the automation of the power systems by means of microprocessor and fibre optic technology.

While the Hydro-Québec research program is primarily dedicated to provincial research priorities, IREQ performs research on contract for other countries.

Ontario Hydro

R&D expenditures by Ontario Hydro totalled $54.3 million in 1981. About $26.8 million of those resources were allocated to the principal work areas controlled by the Research Division. The area of transmission and distribution received $7 million; nuclear power $13.1 million; thermal coal plants $0.8 million; solar, wind and other generation $1.4 million; air and water studies $3.5 million; and energy conservation and utilization $1.1 million. The remaining $27.5 million was allocated to development work undertaken by engineering and design sections in the Corporation and to materials and product testing.

Transmission and distribution program studies included a number of research possibilities; namely, a proposed interconnection with General Public Utilities Co. Ltd. in Pennsylvania by a high voltage, direct current cable under Lake Erie; the development of aesthetically improved transmission lines for use in highly populated and environmentally sensitive areas; and development of insulators to reduce interference from distribution.

Saskatchewan Power

R&D expenditures by Saskatchewan Power totalled $1.9 million in 1981. Saskatchewan Power's Research and Development Centre emphasizes projects related to coal conversion technology, biomass, unconventional energy utilization, and conservation and system operation. Included among the major projects defined within these broad areas are studies on coal reactivity, coal-heavy crude liquifaction, transmission line protective relaying, load management, load diversity and the expansion of rural systems to meet electric heating needs.

Manitoba Hydro

Manitoba Hydro, in conjunction with the Government of Manitoba, the University of Manitoba, Teshmont Consultants Inc. and Federal Pioneer Limited have established the Manitoba HVDC Research Centre. The Centre, established in 1982, is directed at analytical and developmental research of HVDC transmission systems. Initial funding has been provided by the Manitoba Government, totalling $3.75 million over the first five years, and by Manitoba Hydro, totalling $1.25 million over the same period. The Centre expects to be self-supporting by the end of 1987.

The first research project is under contract from EPRI. It involves research into the multi-terminal operation of HVDC systems. IREQ and the University of Wisconsin are also involved in this research. In addition, a contract for the monitoring of ion drift and corona on the operational Manitoba Hydro lines has been signed with the Government of Canada for NRC. The Centre is currently involved in identifying and evaluating future research projects.

B.C. Hydro

B.C. Hydro's research and development organization is involved in chemical, material and electrical research conducted by the research group, as well as research projects conducted elsewhere in the corporation, on wind generation of electricity, geothermal energy, thermography, coal liquifaction and pressurized fluidized bed combustion. Expenditure data for 1981 are not yet available.

Rather than pursuing research as a corporate goal, B.C. Hydro's research and development expertise is aimed at providing a service to clients within the corporation in order to maintain an adequate, reliable, cost-effective and safe supply of electricity.

Canadian Electrical Association

The CEA's research program expanded to $7.8 million in 1981. These resources were allocated among subcommittees as follows: $2.6 million to the generation program; $2.0 million to the transmission systems program; $2.3 million to the distribution program; and $0.9 million to utilization and conservation.

The Generation Subcommittee is divided into three sectors: fossil and nuclear plant subjects; hydroelectric plant subjects; and alternate energy technologies and energy management subjects. Among the 22 projects initiated in 1981 were studies on the potential application of the wind-diesel hybrid system in remote areas; potential reductions of SO_2 emissions in North America; enhancement of coal ash utilization; and evaluation of wastewater management. In 1982 the committee plans to establish an advisory panel in the area of flue gas desulfurization, resulting from the recently released Federal emission control guidelines. The overall focus of the generation program continues to be the improvement of the reliability and efficiency of conventional thermal and nuclear generating components; the reduction of capital costs; the enhancement of environmental protection; and the development of new technologies.

The Transmission System Program is not only directed to improving existing technologies but to the development of advanced technology for increased system security. Areas of high priority are gas-insulated apparatus, synthetic insulators, conductor dynamics and HVDC transmission. The working groups formed last year in each of these areas have been instrumental in reviewing proposals and initiating projects in these areas.

The Distribution Program is broadly classified into areas pertaining to overhead and underground distribution systems as well as systems planning and control. In order to ensure continued development of a balanced program, priority is given to projects with consideration to the following:

— environmental, aesthetic, material, higher voltage and surge protection aspects of overhead systems;

ENVIRONMENTAL ISSUES

— safety, material, loading/ampacity and switching/overcurrent protection of underground systems; and
— conservation, reliability, system design/forecasting, automation and load control considerations associated with planning and control.

The emphasis of the Utilization and Conservation Subcommittee is on the efficient use of electrical resources and the conservation of energy. Several areas of relevant research for the next five year period have been identified. Within the utility sector, research will be selected to provide guidance on policy formation, waste heat recovery and demand management. Studies directed to the residential and farm sectors will include: solar applications for grain driers, biomass, micro hydro and electrical space heating. Investigations into industrial and commercial applications include: techniques for power factor correction, improved motor efficiency, auxiliary system efficiency, gains in plant efficiency from cogeneration and, in support of the National Energy Program, oil substitution by electricity. Candidate research areas for the transportation sector include railway electrification and battery development, recharging and space heating for electric automobiles. During 1981 particular attention was directed at the energy consumer with respect to public attitudes, and to energy conservation projects. Contracts were awarded for the development of an air-to-air heat pump for domestic use and for studies into the applications of high temperature industrial heat pumps. The committee has also formed a task force to assess R&D developments in the areas of air quality, heat exchange and humidity in energy efficient homes.

The generation and distribution of electricity affects the environment in a variety of ways. As one might expect, the environmental issues are determined by the method used to generate electricity. Hydro-electric developments must take into account such considerations as the effect on water temperature, rates of flow, fluctuations of water levels, as well as effects on vegetation and aquatic life. A dominant concern linked to nuclear power generation is the disposal of radioactive wastes, a subject receiving a great deal of attention, as noted in the Research and Development section. In the transmission of electricity, one area of concern is over the potential environmental problems resulting from the use of polychlorinated byphenols (PCB) in electrical transmission equipment. B.C. Hydro has initiated a program to replace and reduce the use of existing PCB capacitors and transformers at an estimated cost of $5.5 million. Several other utilities such as Hydro-Québec and Ontario Hydro are also studying this problem.

Perhaps the most significant of the environmental problems facing the electric industry concerns conventional thermal generation. This problem is linked to the issue of acid rain. The term refers to the problem caused by emissions of sulphur and nitrogen oxides which combine with atmospheric moisture to produce sulphuric acid and nitric acid which then return to the ground as acid rain or acid snow. It also encompasses dry deposition – when dry particles of SO_2 and NO_x fall to the earth before this chemical transformation occurs; the particles become acidic when combined with surface water. These two processes occur with roughly equal frequency.

The release of pollutants linked to acid rain results from activities in various industrial and non-industrial sectors: transportation, non-ferrous smelting, non-utility and utility boilers, etc. About 15% of the increased demand for electricity in Canada, between 1981 and 1994 will be met by coal-fired generation, one of the contributors to sulphur dioxide emissions. Although this is not a major part of the total additional capacity, the additional fuel burned, together with existing coal requirements could add to the acid rain problem, if not handled appropriately.

Acid rain has far-reaching implications for all aspects of the environment. It alters the ph levels of soil and of water bodies which can cause changes in the level and quality of aquatic life and vegetation. The full ramifications of acid rain are not yet known, but sufficient information exists for its seriousness to be understood.

Because SO_2 and NO_x are transported over long distances through the atmosphere, acid rain is not a localized phenomenon. While there is some particulate and gaseous deposition in the immediate vicinity of an emitting source, the trend toward building taller stacks in order to relieve local pollution problems, has aggrevated regional, interprovincial and international problems. It is estimated that approximately 4 million metric tonnes of SO_2 are deposited in Canada annually from sources in the United States and between 500-700 thousand tonnes are deposited in the U.S. from Canadian sources. About 60% of Canadian emissions from east of Manitoba come from non-ferous smelters and about 15% from thermal power stations. The balance is mainly from industrial processes and non-utility fuel use.

In November 1981, the International Electric Research Exchange (IERE) released a report entitled "Effects of SO_2 and its derivatives on health and ecology". IERE is represented by the Canadian Electrical Association, the Electric Power Research Institute, the Japan IERE Council and the International Union of Producers and Distributors of Electrical Energy. The study reports the results of two Working Groups who, for over three years, have analyzed the scientific evidence of the health and ecological effects of air pollutants. The two Working Groups, one considering the effects on human health and the second the environmental effects, assessed and reviewed over 900 documents.

The findings of the report indicate that although the effects of high concentrations of SO_2 and its derivatives can be determined to some extent, the effects of lower levels are more obscure. This obscurity with respect to the effects on human health is due to demographic differences and to the effects of smoking, which confound population data. It has been determined that sulphuric acid is a greater irritant that sulphur dioxide and that there are wide degrees of sensitivity in the population. However, there is a protective mechanism in human air passages which serves to neutralize some

amounts of inhaled sulphuric acid aerosol.

In the environment, the report found evidence that high levels of SO_2, such as may occur near a large emission source, can cause visible plant injury. At lower levels, plant growth can be inhibited, although there is large variation in sensitivity between species of plants. Similarly, different types of soil vary in their sensivity to acid rain and the acidification of lakes is largely determined by the nature of the soil in the lake catchment. Acids in rain also react with soil minerals and therefore may affect the levels of aluminium and calcium released into the lakes. The levels of these minerals, as well as acidity levels, affect aquatic life and vegetation. The effects of SO_2 experienced at locations remote from the emitting source are difficult to determine. It appears that low emission levels cause small effects which will require long-term analysis to quantify. Due to the complexity of the interrelationships, the report concludes that acid deposition is only one of many factors to be investigated. It further suggests a number of areas that warrent additional study, which may serve to clarify the effects of acidification.

Canada – U.S. Negotiations

Negotiations between Canada and the United States on a treaty to deal with long range transport of air pollutants, especially that linked to acid rain, have been continuing for over a year. These talks are held under the 1980 Memorandum of Intent between the U.S. and Canada to work toward such an agreement. It is anticipated that the discussions could continue for at least an additional year, due to the differing perspectives between the two countries on dealing with the problem. Four negotiating sessions have been held so far.

Canada has recently proposed a 50% reduction in Canadian sulphur dioxide emissions east of Saskatchewan by 1990, contingent upon similar actions in the eastern U.S. The U.S. response has been that such a commitment would be premature in light of its view on the adequacy of the scientific data, and also in light of depressed economic conditions. However the U.S. government plans to increase the budget for acid rain research by about 28%, to $23 million in 1983. This move reflects the U.S. view that actions should focus on more research rather than increased controls.

As a result of consideration in the U.S. Congress regarding revisions to the U.S. Clean Air Act prior to its reauthorization, acid rain has received increased attention in the U.S. Consideration is being given both to possible relaxing of the clean air laws or alternatively, to possible strengthening of these laws.

At the present time, in the United States, there are about 87 flue gas desulphurization units, or 'scrubbers', installed on fossil-fired generating units and an additional 22 are being installed. Regulations of the Environmental Protection Agency (EPA) requires that all new fossil-fired plants have scrubbers installed. These standards do not apply to existing stations or to those converting from oil to coal. This policy is consistant with that of a number of other countries faced with acid rain problems, who argue that retrofitting scrubbers to older plants or to reconverted plants could make them uneconomical.

Response to Acid Rain

In Canada a number of measures are being taken to curb emission levels. The Federal and Nova Scotia governments have recently announced a $4.1 million pilot project to test fluidized bed combustion of coal as an alternative to scrubbers. The experiment is being conducted at the Nova Scotia Power Corporation's Point Tupper generating station.

Under the National Energy Program, funding for conversions from oil to coal fired generating stations is contingent upon the conversion being undertaken in an environmentally acceptable fashion. The governments of Manitoba, Ontario, Québec and New Brunswick are committed to the 50% reduction in emissions contingent upon similar actions in the eastern U.S. It is within provincial jurisdiction to control emissions. Federal authority exists only with an international agreement. The Ontario Government has initiated a program aimed at a 43% reduction in emissions by 1990. The program includes controls placed on major contributors such as Inco and Ontario Hydro. The utility has announced plans to install scrubbers at either Nanticoke or Lambton coal-fired generating stations at an estimated cost of $250 million. In addition to the purchase of only washed coal, Ontario Hydro blends Canadian and U.S. coal to reduce sulphur dioxide emissions by about 15%. Total utility emissions should be cut in half by 1990.

In Alberta, maximum source emission limits for particulates have been set, as well as ambient ground level concentrations for SO_2, NO_x, and particulates. As a result, Alberta Power is to install new electrostatic precipitators at the Sheerness Station, which is presently under construction, and will retrofit precipitators on Battle River units one to four. When Unit five was commissioned, an electrostatic precipitater had already been installed. Capital costs involved in meeting these environmental requirements at the two stations totalled about $86 million, while operating and maintenance costs for monitoring total about $170,000 per annum.

Scientific research into acid rain is carried out by a number of Federal departments in Canada including: Environment, Fisheries and Oceans, National Health and Welfare and Energy, Mines and Resources. These R&D programs were expanded significantly in 1980 with four-year increases in funding of $10.0 million to Environment, $12.4 million to Fisheries and Oceans, and $3.7 million to Health and Welfare. These departments contribute to the Federal Long-Range Transport of Air Pollutants (LRTAR) Program. The program has three sections: Scientific Studies, Information Projects and Control Strategies Program Studies. Coordination of the program is provided by the Interdepartmental LRTAP Committee. The program was initiated to enhance the scientific and technical understanding of the implications of LRTAP and acidic precipitation. Due to the enormity of the problem and the many areas which require further investigation, expansion of this program is being considered.

In addition, research into the effects of acid rain/LRTAP are conducted by the provinces, by academic institutions and in the private sector. The Federal-Provincial Management Board coordinates the activities of the federal and provincial governments in emission reductions, research and public information.

SELECTED BIBLIOGRAPHY

For readers requiring additional statistical information, the following publications are issued in English and French by the Manufacturing and Primary Industries Division, Statistics Canada. Copies may be ordered from:

Statistics Canada
Ottawa, Ontario
Canada
K1A 0T6

Electric Power Statistics, Volume I – Annual Electric Power Survey of Capability and Load (Catalogue No. 57-204)

Presents the results of the annual electric power survey of capability and load and covers all producers of electrical energy in Canada which generate or will generate 20 million kWh per annum or more during the forecast period.

Electric Power Statistics, Volume II – Annual Statistics (Catalogue No. 57-202)

Includes various statistics, on an annual basis, for electric utilities and industrial establishments including installed capacity, generation, supply and disposal, number of customers, revenue, energy transfers, domestic and farm service, and transmission mileage. Statistics on fuels, employees, wages and salaries, assets and liabilites, income account, taxes and capital and repair expenditures are also included for electric utilities.

Electric Power Statistics, Volume III – Inventory of Prime Mover and Electric Generating Equipment (Catalogue No. 57-206)

Provides a detailed listing of prime mover and generating equipment above 500 kW on an annual basis.

Electric Power Statistics, Monthly (Catalogue No. 57-001)

Presents, on a monthly basis, preliminary electrical energy statistics.

Electricity Bills for Domestic, Commercial and Small Power Service (Catalogue No. 57-203)

Based on the rate schedules supplied by the power companies and municipalities responsible for the distribution of electrical energy in the cities and towns covered in an annual survey. Monthly bills are computed to show the revenue according to the distributors from the sale of definite quantities of electricity used for specific purposes.

Quarterly Report on Energy-Supply-Demand in Canada (Catalogue No. 57-003)

Energy balance sheets in both natural units and terajoules for fuel types by region. Each balance sheet shows data on production, imports, exports, interregional movements, conversion from one energy form to another, and consumption by consuming sectors.

The following publications are available from distributors of Canadian government publications, or from the OECD Publications Office, 2 rue André-Pascal, 75 Paris 16e, France.

Organization for Economic Cooperation and Development, Survey by the Energy Division, Annual Survey of Electric Power Equipment, Situation and Prospects.

Combines the results of two studies carried out by the OECD:

- Survey of the Energy Division in the development of capital equipment in the electricity supply industry and its technical characteristics (Part One)
- Survey of the Special Committee for Machinery on the trends of deliveries, orders on hand and production capacity of European manufacturers of heavy equipment for power stations (Part Two)

These two complementary surveys show the situation as of January 1st and give an indication of trends for the next 5 years.

Organization for Economic Cooperation and Development, Energy Division, The Electricity Supply Industry

Annual general review of the electricity supply industry in OECD countries in the last 2 years and provides an outlook for the following five years.

Organization for Economic Cooperation and Development, Economic Statistics and National Accounts Division, Statistics of Energy

Presents annually a set of basic statistics on production, trade consumption, etc. for each source of energy, following a standard pattern so that they are presented in consolidated and comparable form.

In addition, more detailed information on individual foreign countries can be obtained by contacting individual electric utilities or government agencies.

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Adelaar, Martin and Associates with Communitech and Associates; *Community Specific Energy Supply in the Yukon and Northwest Territories*. August 1981.

Adelaar, Martin and Associates; *Energy Demand and Supply in the Northwest Territories*. February 1981.

Hildebrandt – Young and Associates;

- *Market Forecast, Electric Energy Requirements in the Yukon Territory 1980/81 – 2000/2001*. June 1981.
- *Projected Yukon Energy Requirements 1980-1991*. October 1981.
- Update: *Market Forecast, Electric Energy Requirements in the Northwest Territories 1980/81 – 2000/2001*. June 1981.

Northern Canada Power Commission; Annual Report.

Northern Energy Task Force; *Task Force Report on an Energy Strategy for Northerners*, November 1981.

Subcommittee on the Northern Canada Power Commission; *Electric Power North of 60°*. April 1982.

APPENDICES

Table A1 Installed Capacity and Electrical Energy Consumption in Canada, 1920-1981

Year	INSTALLED CAPACITY					Electrical Energy Consumption	Average Demand	Peak Demand	Generation Reserve		Load Factor
	Thermal										
	Conventional	Nuclear	Sub-Total	Hydro	Total						
	(MW)					(a) (GWh)	(b) (MW)	(c) (MW)	(MW)	(d) %	(e) %
1920	300	–	300	1 700	2 000	–	–	–	–	–	–
1930	400	–	400	4 300	4 700	19 468	2 222	–	–	–	–
1940	500	–	500	6 200	6 700	33 062	3 774	–	–	–	–
1950	900	–	900	8 900	9 800	55 037	6 283	–	–	–	–
1955	2 100	–	2 100	12 600	14 700	81 000	9 247	12 536	2 164	15	74
1960	4 392	–	4 392	18 657	23 049	109 302	12 477	17 264	5 785	25	72
1961	5 072	–	5 072	19 019	24 091	110 950	12 666	18 353	5 738	24	69
1962	5 609	20	5 629	19 338	24 967	116 135	13 257	18 937	6 030	24	70
1963	6 180	20	6 200	20 101	26 301	121 510	13 871	20 783	5 518	21	67
1964	6 694	20	6 714	20 313	27 027	133 949	15 291	22 516	4 511	17	68
1965	7 557	20	7 577	21 771	29 348	144 165	16 457	24 167	5 181	18	68
1966	8 307	20	8 327	22 438	30 765	156 956	17 917	25 921	4 844	16	69
1967	9 373	240	9 613	23 353	32 966	165 812	18 928	27 812	5 154	16	68
1968	10 711	240	10 951	24 957	35 908	76 841[r]	20 187[r]	30 300	5 608	16	67[r]
1969	12 321	240	12 561	27 031	39 592	189 522[r]	21 635[r]	32 092	7 500	19	67
1970	14 287	240	14 527	28 298	42 826	202 337[r]	23 098[r]	34 592	8 234	19	67[r]
1971	14 504	1 570	16 075	30 601	46 676	212 882[r]	24 302[r]	35 720	10 956	23	68
1972	15 318	2 126	17 444	32 500	49 944	231 557[r]	26 433[r]	38 921	11 023	22	68[r]
1973	17 711	2 400	20 111	34 266	54 376	249 298[r]	28 459[r]	42 699	11 677	21	67[r]
1974	18 085	2 666	20 751	36 779	57 530	266 956[r]	30 747[r]	42 528	15 002	26	72
1975	21 404	2 666	24 070	37 282	61 352	265 955[r]	30 360[r]	46 187	15 165	25	66
1976	23 039	3 466	26 505	39 488	65 993	284 829[r]	32 515[r]	49 537	16 456	25	66[r]
1977	24 699	5 066	29 765	40 810	70 575	299 673[r]	34 209[r]	52 001	18 574	26	66[r]
1978	26 154	5 866	32 020	41 898	73 918	316 435[r]	36 123[r]	54 106	19 812	27	67[r]
1979	27 353[r]	5 866	33 219[r]	44 009[r]	77 228[r]	323 465[r]	36 925[r]	55 699	21 529[r]	28	66
1980	27 853	5 866	33 719	47 919	81 634	340 069[r]	38 821[r]	59 170[r]	22 464[r]	28[r]	66[r]
1981*	28 493	5 600	34 093	49 216	83 308	343 748	39 241	62 874	20 434	25	62

(a) *1920-55: figures are approximate, computed using actual Statistics Canada data for stations generating energy for sale to which have been added estimates for stations generating entirely for own use. 1920-55 Canadian Energy Prospects (Royal Commission on Canada's Economic Prospects) John Davis, 1957. 1956-81, Statistics Canada Publication 57-202.*

(b) *Average Demand = Energy Consumption ÷ 8 760 (hrs/yr).*

(c) *Statistics Canada Publication 57-204.*

(d) *Generation Reserve Data is based on capacity. These figures differ from those presented by Statistics Canada Publication 57-204 as latter are based on capability.*

(e) *Load Factor = Average Demand ÷ Peak Demand.*

* *Preliminary Data.*

[r] *Revised Figures.*

Table A2 Installed and Proposed Generating Capacity, 1981

Province	Hydro	Nuclear	Conventional Thermal*	Total	% of Canadian Total
Newfoundland	6 210	–	750	6 961	8.4
Prince Edward Island	–	–	118	118	**
Nova Scotia	360	–	1 669	2 029	2.4
New Brunswick	901	–	1 894	2 795	3.4
Québec	20 771	–	1 184	21 955	26.4
Ontario	7 145	5 600	13 242	25 987	31.2
Manitoba	3 641	–	501	4 142	5.0
Saskatchewan	579	–	1 761	2 340	2.8
Alberta	718	–	5 464	6 182	7.4
British Columbia	8 785	–	1 740	10 525	12.6
Yukon	58	–	36	94	**
Northwest Territories	47	–	133	180	**
Canada Total At Dec. 31, 1981***	49 216	5 600	28 493	83 308	–
Percent of Total Capacity, End 1981	59	7	34	100	–
Net additions During 1981***	1 679	–	577	2 256	–
Planned additions During 1982	720	630	477	2 067	–

* *Details provided in Table A3. Conventional thermal includes steam, gas turbine, internal combustion.*
** *Less than 0.5%.*
*** *Preliminary Data.*

Table A3 Conventional Thermal Capacity by Principal Fuel Type. Preliminary Figures as of December 31, 1981

Province	Steam					Gas Turbine			Internal Combustion			All Conventional Thermal				
	Coal	Oil	Gas	Other*	Total	Oil	Gas	Total	Oil	Gas	Total	Coal	Oil	Gas	Other*	Total
									(MW)							
Newfoundland	–	503	–	–	503	170	–	170	77	–	77	–	750	–	–	750
Prince Edward Island	–	71	–	–	71	41	–	41	7	–	7	–	118	–	–	118
Nova Scotia	637	826	–	–	1 463	205	–	205	1	–	1	637	1 032	–	–	1 669
New Brunswick	285	1 558	–	23	1 866	23	–	23	5	–	5	285	1 586	–	23	1 894
Québec	–	635	4	16	655	363	–	363	166	–	166	–	1 164	4	16	1 184
Ontario	8 913	2 330	1 411	85	12 739	493	–	493	4	6	10	8 913	2 827	1 417	85	13 242
Manitoba	419	24	4	–	447	24	–	24	30	–	30	419	78	4	–	501
Saskatchewan	1 475	–	143	21	1 639	–	104	104	19	–	19	1 475	18	247	21	1 761
Alberta	3 673	66	1 285	75	5 098	–	325	325	11	30	41	3 673	77	1 640	75	5 464
British Columbia	–	86	969	202	1 258	188	154	342	122	18	140	–	396	1 141	202	1 740
Yukon	–	–	–	–	–	–	–	–	36	–	36	–	36	–	–	36
N.W.T.	–	1	–	–	1	–	–	–	132	–	132	–	133	–	–	133
CANADA	15 401	6 101	3 816	422	25 739	1 507	583	2 090	610	54	664	15 402	8 215	4 453	425	28 493

* *Mainly wood wastes and black liquor.*

Table A4 Electrical Energy Production by Principal Fuel Type, Preliminary Figures 1981

Province	CONVENTIONAL THERMAL							Percentage Generated By		
	Coal*	Oil*	Gas*	Total	Nuclear	Hydro	Total	Percentage of Total Generation	Utilities	Industrial Establishments
					(GWh)				(%)	
Newfoundland	–	454	–	454	–	44 212	44 665	11.8	98.8	1.2
Prince Edward Island	–	31	–	31	–	–	31	.0	100.0	.0
Nova Scotia	2 710	2 692	–	5 402	–	1 167	6 569	1.7	93.5	6.5
New Brunswick	1 107	3 998	–	5 105	–	3 830	8 936	2.4	92.0	8.0
Québec	–	173	3	176	–	102 730	102 905	27.3	82.4	17.6
Ontario	33 430	328	1 148	34 906	37 799	37 335	110 039	29.1	96.0	4.0
Manitoba	399	124	9	532	–	17 899	18 431	4.9	99.3	0.7
Saskatchewan	5 898	62	616	6 576	–	3 097	9 674	2.6	95.7	4.3
Alberta	18 163	16	4 282	22 461	–	2 035	24 497	6.5	94.6	5.4
British Columbia	–	912	685	1 597	–	49 408	51 005	13.5	76.0	24.0
Yukon	–	102	–	102	–	290	392	0.1	100.0	.0
Northwest Territories	–	230	–	230	–	250	480	0.1	95.3	4.7
CANADA	61 707	9 122	6 743	77 570	37 799	262 253	377 622	100.0	89.8	10.2

* *Estimated values.*
SOURCE: Statistics Canada.

Table A5 Provincial Electricity Imports and Exports (GWh)

Province	Year	Interprovincial Trade			International Trade			Total Net Exports
		Exports	Imports	Net Exports	Exports	Imports	Net Exports	
Newfoundland	1981	36 039	–	36 039	–	–	–	36 039
	1980	37 829	–	37 829	–	–	–	37 829
	1979	35 290	–	35 290	–	–	–	35 290
Prince Edward Island	1981	–	484	–484	–	–	–	–484
	1980	–	392	–392	–	–	–	–392
	1979	–	361	–361	–	–	–	–361
Nova Scotia	1981	125	317	–192	–	–	–	–192
	1980	226	172	54	–	–	–	54
	1979	151	494	–343	–	–	–	–343
New Brunswick	1981	801	3 846	–3 045	3 246	54	3 192	147
	1980	564	3 901	–3 337	3 877	54	3 823	486
	1979	856	3 739	–2 883	3 890	24	3 866	983
Québec	1981	10 208	36 098	–25 890	8 313	7	8 306	–17 584
	1980	9 442	37 879	–28 437	8 107	6	8 101	–20 336
	1979	8 977	35 494	–26 517	7 663	5	7 658	–18 859
Ontario	1981	60	7 705	–7 645	11 310	343	10 967	3 322
	1980	50	7 342	–7 292	11 314	248	11 066	3 774
	1979	227	7 216	–6 989	12 193	420	11 774	4 785
Manitoba	1981	2 508	1 066	1 442	3 681	194	3 487	4 929
	1980	3 154	951	2 203	3 529	192	3 337	5 540
	1979	3 075	795	2 280	4 080	1	4 080	6 360
Saskatchewan	1981	1 068	1 290	–222	–	–	–	–222
	1980	955	1 579	–624	–	–	–	–624
	1979	774	1 247	–473	–	–	–	–473
Alberta	1981	262	168	94	–	2	–2	92
	1980	385	104	281	–	2	–2	279
	1979	394	106	288	–	2	–2	286
British Columbia	1981	165	262	–97	8 821	897	7 924	7 827
	1980	100	385	–285	3 350	2 437	913	628
	1979	103	394	–291	3 552	1 342	2 210	1 919
Yukon	1981	–	–	–	–	–	–	–
	1980	–	–	–	–	–	–	–
	1979	–	–	–	–	–	–	–
N.W.T.	1981	–	–	–	–	–	–	–
	1980	–	–	–	–	–	–	–
	1979	–	–	–	–	–	–	–
CANADA	1981	–	–	–	35 372	1 497	33 875	33 875
	1980	–	–	–	30 176	2 939	27 237	27 237
	1979	–	–	–	31 378	1 792	29 586	29 586

Table A6 Generation Capacity by Type

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
			(MW)				
NEWFOUNDLAND							
Total End 1980	502.60	170.39	77.43	–	750.42	6 210.26	6 960.68
Additions 1981	–	–	–	–	–	–	–
Total End 1981	502.60	170.39	77.43	–	750.42	6 210.26	6 960.68
Additions Proposed							
1982	–	–	–	–	–	84.00	84.00
1983	–	–	–	–	–	3.75	3.75
1984	–	–	–	–	–	131.50	131.50
1985	–	25.00	–	–	25.00	–	25.00
Total End 1985	502.60	195.39	77.43	–	775.42	6 429.51	7 204.93
PRINCE EDWARD ISLAND							
Total End 1980	70.50	40.85	6.89	–	118.24	–	118.24
Additions 1981	–	–	–	–	–	–	–
Total End 1981	70.50	40.85	6.89	–	118.24	–	118.24
Additions Proposed							
1982	–	–	–	–	–	–	–
Total End 1982	70.50	40.85	6.89	–	118.24	–	118.24
NOVA SCOTIA							
Total End 1980	1 463.28	205.00	0.60	–	1 668.88	359.90	2 028.78
Additions 1981	–	–	–	–	–	–	–
Total End 1981	1 463.28	205.00	0.60	–	1 668.88	359.90	2 028.78
Additions Proposed							
1982	–	–	–	–	–	6.00	6.00
1983	–	–	–	–	–	20.00	20.00
1984	150.00	–	–	–	150.00	–	150.00
1985	150.00	–	–	–	150.00	–	150.00
Total End 1985	1 763.28	205.00	0.60	–	1 968.88	385.90	2 354.78
NEW BRUNSWICK							
Total End 1980	1 865.63	23.38	4.84	–	1 893.85	900.93	2 794.78
Additions 1981	–	–	–	–	–	–	–
Total End 1981	1 865.63	23.38	4.84	–	1 893.85	900.93	2 794.78
Additions Proposed							
1982	–	–	–	630.00	630.00	–	630.00
Total End 1982	1 865.63	23.38	4.84	630.00	2 523.85	900.93	3 424.78
QUÉBEC							
Total End 1980	655.25	362.88	155.68	–	1 173.81	19 091.09	20 264.90
Additions 1981	–	–	10.54	–	10.54	1 679.45	1 689.99
Total End 1981	655.25	362.88	166.22	–	1 184.35	20 770.54	21 954.89
Additions Proposed							
1982	–	–	–	–	–	576.00	576.00
1983	–	–	–	685.00	685.00	1 536.00	2 221.00
1984	–	–	–	–	–	2 243.00	2 243.00
1985	–	–	–	–	–	1 574.00	1 574.00
1986	–	–	–	–	–	–	–
1987	–	–	–	–	–	510.00	510.00
1988	–	–	–	–	–	1 275.00	1 275.00
1989	–	–	–	–	–	1 884.00	1 884.00
1990	–	–	–	–	–	2 060.02	2 060.02
1991	–	–	–	–	–	2 112.00	2 112.00
Total End 1991	655.25	362.88	166.22	685.00	1 869.35	34 540.56	36 409.91

Table A6 (Continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
			(MW)				
ONTARIO							
Total End 1980	12 590.31	450.64	10.02	5 600.00	18 650.97	7 145.31	25 796.28
Additions 1981	149.00	42.00	–	–	191.00	–	191.00
Total End 1981	12 739.31	492.64	10.02	5 600.00	18 841.97	7 145.31	25 987.28
Additions Proposed							
1982	149.00	28.00	–	–	177.00	54.00	231.00
1983	–	28.00	–	1 788.00	1 816.00	–	1 816.00
1984	206.00	–	–	1 788.00	1 994.00	–	1 994.00
1985	–	42.00	–	–	42.00	–	42.00
1986	–	–	–	756.00	756.00	–	756.00
1987	–	–	–	756.00	756.00	–	756.00
1988	–	14.00	–	881.00	895.00	–	895.00
1989	–	–	–	881.00	881.00	–	881.00
1990	–	–	–	881.00	881.00	–	881.00
1991	–	–	–	881.00	881.00	–	881.00
Total End 1991	13 094.31	604.64	10.02	14 212.00	27 920.97	7 199.31	35 120.28
MANITOBA							
Total End 1980	447.00	23.80	30.35	–	501.15	3 641.10	4 142.25
Additions 1981	–	–	–	–	–	–	–
Total End 1981	447.00	23.80	30.35	–	501.15	3 641.10	4 142.25
Additions Propcsed							
1992	–	–	–	–	–	240.00	240.00
1993	–	–	–	–	–	600.00	600.00
1994	–	–	–	–	–	360.00	360.00
Total End 1994	447.00	23.80	30.35	–	501.15	4 841.10	5 342.25
SASKATCHEWAN							
Total End 1980	1 638.96	103.92	18.53	–	1 761.41	578.74	2 340.15
Additions 1981	–	–	–	–	–	–	–
Total End 1981	1 638.96	103.92	18.53	–	1 761.41	578.74	2 340.15
Additions Proposed							
1982	300.00	–	–	–	300.00	–	300.00
1983	–	–	–	–	–	–	–
1984	–	–	–	–	–	–	–
1985	–	–	–	–	–	168.00	168.00
1986	–	–	–	–	–	84.00	84.00
Total End 1986	1 938.96	103.92	18.53	–	2 061.41	830.74	2 892.15
ALBERTA							
Total End 1980	4 723.43	324.50	40.90	–	5 088.83	718.30	5 807.13
Additions 1981	375.00	–	–	–	375.00	–	375.00
Total End 1981	5 098.43	324.50	40.90	–	5 463.83	718.30	6 182.13
Additions Proposed							
1982	–	–	–	–	–	–	–
1983	400.00	–	–	–	400.00	–	400.00
1984	400.00	–	–	–	400.00	–	400.00
1985	780.00	–	–	–	780.00	–	780.00
1986	1 180.00	–	–	–	1 180.00	–	1 180.00
1987	400.00	–	–	–	400.00	–	400.00
Total End 1987	8 258.43	324.50	40.90	–	8 623.83	718.30	9 342.13

Table A6 (Continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
			(MW)				
BRITISH COLUMBIA							
Total End 1980	1 257.79	342.20	139.76	–	1 739.75	8 784.92	10 524.67
Additions 1981	–	–	–	–	–	–	–
Total End 1981	1 257.79	342.20	139.76	–	1 739.75	8 784.92	10 524.67
Additions Proposed							
1982	–	–	–	–	–	–	–
1983	–	–	–	–	–	921.50	921.50
1984	–	–	–	–	–	921.50	921.50
1985	–	–	–	–	–	–	–
1986	–	–	–	–	–	–	–
1987	–	–	–	–	–	–	–
1988	–	–	–	–	–	372.00	372.00
1989	560.00	–	–	–	560.00	672.00	1 232.00
1990	560.00	–	–	–	560.00	–	560.00
1991	–	–	–	–	–	80.00	80.00
1992	–	–	–	–	–	320.00	320.00
Total End 1992	2 377.79	342.20	139.76	–	2 859.75	12 071.92	14 931.67
YUKON							
Total End 1980	–	–	36.01	–	36.01	58.14	94.15
Additions 1981	–	–	–	–	–	–	–
Total End 1981	–	–	36.01	–	36.01	58.14	94.15
Additions Proposed							
1982	–	–	–	–	–	–	–
1983	–	–	–	–	–	–	–
1984	–	–	–	–	–	20.00	20.00
Total End 1984	–	–	36.01	–	36.01	78.14	114.15
NORTHWEST TERRITORIES							
Total End 1980	0.60	–	132.42	–	133.02	47.36	180.38
Additions 1981	–	–	–	–	–	–	–
Total End 1981	0.60	–	132.42	–	133.02	47.36	180.38
Additions Proposed							
1982	–	–	–	–	–	–	–
Total End 1982	0.60	–	132.42	–	133.02	47.36	180.38
CANADA							
Total End 1980	25 215.34	2 047.56	653.42	5 600.00	33 516.32	47 536.04	81 052.36
Additions 1981	524.00	42.00	10.54	–	576.54	1 679.45	2 255.99
Total End 1981	25 739.34	2 089.56	663.96	5 600.00	34 092.86	49 215.49	83 308.35
Additions Proposed							
1982	449.00	28.00	–	630.00	1 107.00	720.00	1 827.00
1983	400.00	28.00	–	2 473.00	2 901.00	2 481.25	5 382.25
1984	756.00	–	–	1 788.00	2 544.00	3 316.00	5 860.00
1985	930.00	67.00	–	–	997.00	1 742.00	2 739.00
1986	1 180.00	–	–	756.00	1 936.00	84.00	2 020.00
1987	400.00	–	–	756.00	1 156.00	510.00	1 666.00
1988	–	14.00	–	881.00	895.00	1 647.00	2 542.00
1989	560.00	–	–	881.00	1 441.00	2 556.00	3 997.00
1990	560.00	–	–	881.00	1 441.00	2 060.02	3 501.02
1991	–	–	–	881.00	881.00	2 192.00	3 073.00
1992	–	–	–	–	–	320.00	320.00
1993	–	–	–	–	–	600.00	600.00
1994	–	–	–	–	–	360.00	360.00
Total End 1994	30 974.34	2 226.56	663.96	15 527.00	49 381.32	68 023.76	117 435.62

Table A7 Installed Generating Capacity Expansion in Canada by Station. Major 1981 Additions and Projected 1982-1994

Province	Station	Type	Additions in 1981	Year	Additions Proposed	Status	Proposed plant capacity
			(MW)		(MW)		(MW)
Newfoundland							
	Upper Salmon	H		1982	84.00	C	84.00
	Topsail	H		1983	2.10	P	2.10
	Lawn	H		1983	0.65	P	0.65
	Morris	H		1983	1.00	P	1.00
	Lookout Brook	H		1984	2.60	P	2.60
	Lookout Pond	H		1984	0.90	P	0.90
	Seal Cove	H		1984	1.00	P	1.00
	Cat Arm	H		1984	2 x 63.50	C	127.00
	Port aux Basque	GT		1985	25.00	P	25.00
Nova Scotia							
	Fourth Lake	H		1982	2.5	C	2.50
	Gisborne Canal	H		1982	3.5	C	3.50
	Annapolis Royal	H		1983	20.0	C	20.00
	Lingan	S(C)		1984	150.0	C	
				1985	150.0	P	600.00
New Brunswick							
	Point Lepreau	N		1982	630	C	630.00
Québec							
	Beauharnois(net)	H	5			I	1 579.30
	Bryson (net)	H	9.45			I	65.45
	Delaney	H		1987	2 X 225	P	
				1988	5 X 255	P	
				1989	3 X 255	P	2 550.00
	Gentilly 2	N		1983	685	C	685.00
	Grande Baleine-GB-1	H		1990	2 X 392	P	
				1991	3 X 392	P	1 960.00
	GB-2	H		1991	3 X 160	P	480.00
	GB-3	H		1991	3 X 152	P	456.00
	La Grande – LG-2	H	5 X 333			I	5 328.00
	LG-3	H		1982	3 X 192	C	
				1983	8 X 192	C	
				1984	192	C	2 304.00
	LG-4	H		1984	7 X 293	C	
				1985	2 X 293	C	2 637.00
	LG-1	H		1989	6 X 114	C	
				1990	4 X 114	C	1 140.00
	Brisay	H		1989	2 X 217.5	P	435.00
	La Forge 1	H		1990	6 X 136.67	P	820.02
	Manic 5	H		1985	4 X 247	C	2 280.00
	Various Locations	IC	10.54			I	

Table A7 Installed Generating Capacity Expansion in Canada by Station. Major 1981 Additions and Projected 1982-1994

Province	Station	Type	Additions in 1981	Year	Additions Proposed	Status	Proposed plant capacity
			(MW)		(MW)		(MW)
Ontario							
	Atikokan	S(C)		1984	206	C	206.00
	Bruce B	N		1983	756	C	
				1984	756	C	
				1986	756	C	
				1987	756	C	
		GT		1982	2 X 14	C	
				1983	2 X 24	P	3 080.00
	Darlington	N		1988	881	C	
				1989	881	C	
				1990	881	C	
				1991	881	C	
		GT		1985	3 X 14	P	
				1988	14	P	3 580.00
	Pickering B	N		1983	2 X 516	C	
				1984	2 X 516	C	
		GT	6 X 7.0			I	2 106.00
	St. Mary's	H		1982	3 X 18	C	54.00
	Thunder Bay	S(C)	149			I	
				1982	149	C	447.00
Manitoba							
	Limestone	H		1992	2 X 120	P	
				1993	5 X 120	P	
				1994	3 X 120	P	1 200.00
Saskatchewan							
	Nipawin	H		1985	2 X 84	C	
				1986	84	C	252.00
	Poplar River	S(C)		1982	300	C	600.00
Alberta							
	Battle River	S(C)	375			I	737.00
	Genesee	S(C)		1986	400	C	
				1987	400	C	800.00
	Keephills	S(C)		1983	400	C	
				1984	400	C	
				1985	400	P	
				1986	400	P	1 600.00
	Sheerness	S(C)		1985	380	C	
				1986	380	C	760.00
British Columbia							
	Hat Creek	S(C)		1989	560	P	
				1990	560	P	1 120.00
	Keenleyside	H		1988	2 X 36	P	
				1989	2 X 36	P	144.00
	Murphy Creek	H		1991	2 X 40	P	
				1992	8 X 40	P	400.00
	Peace Site C	H		1988	2 X 150	P	
				1989	4 X 150	P	900.00
	Revelstoke	H		1983	2 X 460.75	C	
				1984	2 X 460.75	C	1 843.00
Yukon							
	Whitehorse	H		1984	20	P	39.39

Legend

H	*Hydro*	*IC*	*Internal Combustion*
S(C)	*Steam (Coal)*	*GT*	*Gas Turbine*
S(G)	*Steam (Gas)*	*W*	*Wind*
S(O)	*Steam (Oil)*	*I*	*Installed*
N	*Nuclear*	*C*	*Under construction*
		P	*Planned*

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